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NELHA HOST Park Microgrid Analysis

Task 3.1: Report on NELHA Power System Requirements Analysis

Task 3.1 - December 14, 2020

HNEI

GridSTART
Hawai'i Natural Energy Institute | University of Hawai'i

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This report was produced as part of extended activities aimed to enhance grid reliability, increase energy assurance, and reduce energy cost and carbon footprint through the assessment of prospective microgrid solutions at the NELHA Hawaii Ocean Science & Technology (HOST) Park. This work is funded by NELHA, a self-sufficient State of Hawaii agency, and is a product of the Hawai′i Natural Energy Institute (HNEI), an Organized Research Unit at the University of Hawai′i at Manoa under University of Hawaii award ID 011866-00002.

This report and its analysis were prepared and authored by HNEI's Grid System Technologies Advanced Research Team (Grid***START***), established to develop and test advanced grid architectures, new technologies and methods for effective integration of renewable energy resources, power system optimization and resilience, and enabling policies.

The opinions, findings, conclusions, or recommendations expressed in this document are those of the author(s) and do not necessarily represent the official position or policies of NELHA. NELHA makes no representation about, nor does it accept responsibility for, the accuracy or completeness of the information contained in this report.

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ATS	Automatic Transfer Switches
CAIDI	Customer Average Interruption Duration Index
DBEDT	Department of Business, Economic Development, and Tourism
DOE	Department of Energy
DER	Distributed Energy Resources
DSW	Deep seawater
ESS	Energy Storage System
FCEB	Fuel Cell Electric Bus
Grid*START*	Grid System Technologies Advanced Research Team
HELCO	Hawaii Electric Light Company
HNEI	Hawaii Natural Energy Institute
HOST	Hawaii Ocean Science and Technology Park
HTDC	High Technology Development Corporation
kV	Kilovolt
kVA	Kilovolt ampere
kVARh	Kilovolt amperes reactive hour
kW	Kilowatt
kWh	Kilowatt-hour
NELHA	Natural Energy Laboratory of Hawaii Authority
ONR	Office of Naval Research
OTEC	Ocean Thermal Energy Conversion
PPA	Power Purchase Agreement
PV	Photovoltaic
RCUH	Research Corporation of the University of Hawaii
SAIFI	System Average Interruption Frequency Index
SCADA	Supervisory Control and Data Acquisition
SLD	Single Line Diagram
SSW	Surface seawater
UPS	Uninterruptible Power Supply

List of Appendices

Appendices to this report are provided as electronic files. The volume and level of detail in the attachments make it difficult to reproduce them in 8.5” × 11” hardcopy format.

Appendix A: NELHA transformers’ serving site and their GPS coordinates

Appendix B: Single-line Diagram of the HOST Park distribution service transformers

Appendix C: Single-line Diagram of the Research Campus

Appendix D: Single-line Diagram of the Host Park excluding the Research Campus

1 Introduction

The Natural Energy Laboratory of Hawaii Authority (NELHA) is an agency of the State of Hawaii administratively attached to the Department of Business, Economic Development, and Tourism (DBEDT). NELHA's mission is to develop and diversify Hawaii's economy by providing resources and facilities for energy and ocean-related research, education, and commercial activities in an environmentally sound and culturally sensitive manner [1]. NELHA administers the 870-acre Hawaii Ocean Science and Technology (HOST) Park located at Keahole Point in North Kona on the Island of Hawaii to promote and provide for the research, development, and commercial application of activities that utilize ocean water as a resource.

The original ocean science and energy concept for the HOST Park was developed in 1974 as a response to the national oil crisis. The Research Corporation of the University of Hawaii (RCUH) and the High Technology Development Corporation (HTDC) originally developed two sites in Kona separately. The two projects in Kona, and a geothermal test site in Puna, were placed under the purview of the newly formed NELHA in 1990. Currently, the leading research and commercial areas of focus at the NELHA HOST Park are: 1) Energy production; 2) Food, aquaculture, and nutraceuticals; 3) Energy research-driven programs; and 4) Public outreach, education, and tourism. The HOST Park has become the world's premier ocean science innovation hub and operates at the nexus of water, energy, and food.

NELHA provides various services, resources, and expertise including seawater utility services, electric power, and energy to its tenants (53 tenants as of September 2020) in the HOST Park, such as laboratories and office spaces. Most critical among the NELHA services and resources is the world's largest seawater utility. Three sets of pipelines deliver cold deep seawater from depths up to 3,000 ft. as well as warm pristine surface seawater. Current equipment and pipeline infrastructure are capable of pumping up to 100,000 gallons of seawater per minute throughout the technology park. To supply uninterrupted seawater to the tenants, NELHA requires a reliable power supply with sufficient on-site emergency backup power and energy in the event of an interruption of primary electric service from the local electric utility, the Hawaii Electric Light Company (HELCO).

Although the HOST Park has diesel backup generators for its critical loads, NELHA's objective is providing a demonstration site for microgrid technologies to further increase its energy resilience and sustainability along with decreasing its carbon footprint. Microgrids that incorporate renewable distributed energy resources (DER) show promise to accomplish this objective. The Department of Energy (DOE) defines a microgrid as ''a group of interconnected loads and distributed energy resources within clearly defined electrical boundaries that act as a single controllable entity with respect to the grid. A microgrid can connect and disconnect from the grid to enable it to operate in both grid-connected or island-mode''. The HOST Park supports loads and has existing and planned renewable DER within clearly defined electrical boundaries. Enabling these loads and possibly existing and planned renewable DER (and existing diesel backup generation) to interconnect and operate while in grid-connected or island-mode as a microgrid is a potential strategy for NELHA to achieve its objective.

In this study, the Grid System Technologies Advanced Research Team (Grid***START***) of the Hawaii Natural Energy Institute (HNEI) will determine the feasibility and benefits of modifying the current energy system at NELHA's HOST Park to incorporate microgrid solutions. The primary goal is to create one or several microgrid(s) that can operate either grid-connected to the HELCO system or in island-mode as a "stand-alone facility" and assess their feasibility. A secondary intent for this study is to maximize the use of renewable DER available and planned within the HOST Park. HNEI will identify regulatory and policy issues currently in place that may hinder the development of such microgrid(s) and offer modifications to those regulations and policies aimed to improve the potential for realization.

The study is divided into three tasks to be completed in sequence. These tasks include 1) NELHA power system requirement analysis, 2) technology information gathering and selection, and 3) microgrid design options analysis. This report contains the results of Task 1. Here, HNEI identified and analyzed the present state of the HOST Park power system based on their site visit and information and feedback provided by the NELHA staff. This report, presenting the foundation upon which potential microgrid scenarios will be designed and assessed, is divided into four primary sections: 1) Introduction, 2) Existing HOST Park power distribution system, 3) Back-up diesel generation and renewable DER, and 4) HOST Park load assessment.

2 Existing HOST Park power distribution system

HELCO currently supplies electric power to the HOST Park and its tenants via two 12.47 kV underground power lines. Power and energy are delivered throughout the HOST Park via thirty (30) distribution service transformers of varying capacity that step down the voltage from 12.47 kV to several load serving voltages (480 V / 277 V / 208 V / 120 V) depending on customer equipment needs. The location of these service transformers is shown in Figure 1.[1] GPS coordinates of these transformers are shown in a table in the Appendix A.

Two of the thirty distribution service transformers are owned by NELHA, with the remainder owned by HELCO. The transformers are shown in the simplified electrical single line diagram (SLD) in Appendix B.

The following five service transformers are metered by HELCO at the transformer and billed to NELHA: (1) Booster pump station, (2) 55" pump station, (3) Kau pump station, (4) Farm Compound, and (5) Research Campus. Understandably, NELHA was only able to provide energy use data for these five transformers for which they are the registered HELCO customer; therefore, the loads served by these five transformers are the primary subject of this study. HOST Park tenants receiving electrical service via the remaining twenty-five HELCO owned service transformers are direct customers of HELCO, and information regarding their energy use is not available to NELHA or HNEI without their express authorization. The five NELHA owned and/or managed loads are discussed in more detail in the next subsection.

[1] This map with high-resolution pictures for each tagged transformer is accessible in the link: https://earth.google.com/web/@19.72038279,-156.04728817,4.72836258a,3093.1704659d,35y,0h,0t,0r/data=MicKJQojCiExSFphdFp5VWZJcjUxS1F6WEt5Q3dueE5DQ3k4OXc5RFA

Figure 1. Location of the HOST Park distribution service transformers

2.1 NELHA owned and/or managed loads at the HOST Park

Major electrical loads at the HOST Park that are the subject of this study are geographically and electrically divided into five sections. Each section is served by the five aforementioned distribution service transformers. Figure 2 shows the electrical load sections: 1) Booster pump station, 2) 55" pump station, 3) Kau pump station, 4) Farm Compound, and 5) Research Campus. The green circles for the Research Campus and the Farm Compound indicate the locations of the electrical load sections and the green circles for the 55" Pump and Booster Pump indicate the locations of the water distribution for each of the pumps. The Kau pump station, which is marked with a yellow circle, is a water pump station serving an average load of only 1.1 kW in 2019. Although this site has a dedicated transformer and a utility meter, it does not currently serve any significant loads. NELHA plans to abandon the site and transfer remaining minimal loads to the Research Campus' secondary distribution service lines. Figure 2 further depicts the location of the surface and deep seawater pipes that deliver essential seawater supply to various HOST Park tenants, as indicated respectively by red and white dotted lines.

Figure 2. Five major electrical load sections owned and managed by NELHA
The image was created using a Google Earth image. The seawater pipes are pictorial representation, not to scale.

2.2 Utility grid architecture

Figure 3 shows the grid connection of the five service transformers that power the HOST Park facilities owned and/or managed by NELHA. The Booster pump station transformer, 55" pump station transformer, and Kau pump station transformer, each shown in blue in Figure 3, are owned by HELCO and are metered at the transformer low voltage secondary. This signifies that HELCO absorbs the cost of energy losses through the transformers and is responsible for their replacement in the event of failure. The remaining two transformers shown in red are owned by <u>NELHA, who bears the cost and responsibility of replacement and the risk of extended service disruption in the event of failure</u>. According to utility tariffs, a credit is reflected on the electric bill for each of these two customer-owned transformers. This credit is calculated as the sum of the demand charge, non-fuel energy charge, and 10.244 cents per kWh multiplied by 2.6% for the Research Campus and 0.7% for the Farm Compound. While a meter at the Research Campus is located on the 12.47 kV primary side and NELHA absorbs the cost for the losses (but receives a larger bill credit with a 2.6% multiplier), a meter at the Farm Compound is located on the secondary side and HELCO absorbs the cost for the losses (but provides a smaller bill credit with a 0.7% multiplier to account for NELHA's ownership of the transformer). The credit for the ownership of the transformers is currently between $150 to $200 per month. The ownership of the transformers does not impact the development of the microgrid architectures being contemplated at the HOST Park.

Regardless of the ownership of transformers and location of the meters, all five HELCO meters, depicted as circles in Figure 3, record and archive data at 15-minute intervals. The data are accessible by the customer from HELCO's meter web portal. The SLD of the buildings and loads supplied by the transformers shown in Figure 3 are provided in Appendices C and D attached to this report.

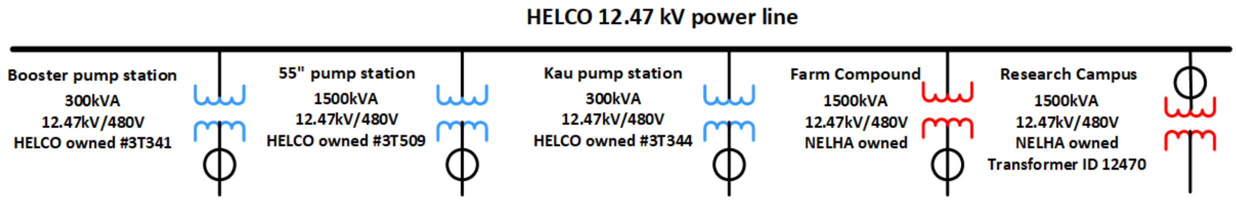

Figure 3. Service transformers supplying the NELHA owned and/or managed loads. HELCO owned transformers are in blue, and NELHA owned transformers are in red.

2.3 Summary of the HOST Park generation resources

Table 1 summarizes the on-site backup diesel generators and NELHA owned and/or managed loads for each of the five service transformers illustrated in Figure 3. The 2019 annual peak demand and average hourly net energy consumption for each of the five transformers along with the nameplate rating of diesel backup generators and renewable DER within each of the five load sections are provided. It is notable that the Kau pump station, which is not currently in use and is planned for abandonment, contains a sizable backup diesel generator asset that may be considered for possible redeployment. The diesel backup generation as well as existing and planned renewable DER are discussed in greater depth in Section 3.

Table 1. Summary of the HOST Park power system (year 2019)

Load section	Transformer peak load in 2019 (kW)	Avg. hourly net energy consumption in 2019 (kWh)	Nameplate capacity of diesel backup generators (kW)	Existing renewable DERs (kW)
Booster pump station	59.60	21.35	500	0
55” pump station	501.36	290.16	750	0
Kau pump station	106.60	1.10	125	0
Farm Compound	204.30	170.90	None	0
Research Campus	368.91	152.64	1,000	184 (PV)

3 Back-up diesel generation and renewable DER

The HOST Park has adequate diesel backup generation to power its critical pumping loads and the entire Research Campus in the event that electric service supply from HELCO is interrupted. There are additional on-site renewable DER that are supplying the Research Campus. These resources include three photovoltaic (PV) systems, one owned by NELHA and commissioned in 2015, and the other two added by NELHA under power purchase agreements (PPA) in the second half of 2019. Section 3.2 further discusses these on-site renewable DER. A new renewable PV system, which is described in detail in Section 3.3, is planned to be operational in 2021 as part of a microgrid demonstration project. Two advanced energy projects are addressed in Section 3.4.

3.1 Back-up generation

The HOST Park's three major pumping stations and Research Campus are each backed up by a diesel generator. Backup diesel generators power up automatically once they detect a power outage. NELHA's technicians are on call 24/7 to respond to power disruption emergencies and planned outage events. The current power backup policy requires that seawater flow to NELHA tenants cannot be interrupted for more than two (2) hours during power disruption emergencies or scheduled outages, and the seawater supply annual availability must be over 99.99% [1]. Table 2 lists basic information about the existing backup generators. NELHA does not have an additional fuel reserve tank at the HOST Park beyond the individual fuel tanks at each generator.

Table 2. List of diesel backup generators

Load section	Manufacturer	Rated capacity (kW)	Fuel tank capacity (gallons)	Age (years)	Approximate fuel consumption (gallons/hour)	Approximate max load run time with a full tank (hours)
Booster pump station	Cummins	500	1,000	14	50	20
55" pump station	Caterpillar	750	2,500	9	65	38
Kau pump station	Caterpillar	125	165	15	9.8	16
Research Campus	Detroit Diesel	1,000	4,000	12-15	77.5	51

3.2 Existing renewable DER

The HOST Park has a total of 184 kW AC of rooftop and ground-mounted PV systems all located at the Research Campus site with no active energy storage system (ESS). In 2015, NELHA commissioned the ground-mounted PV system that is divided into two equal sections, PV1 and PV2. This PV system, owned by NELHA, is oriented south at an appropriate panel tilt angle for a Hawaii installation. A solar company owns the other two rooftop PV systems that were commissioned in 2019 and charges NELHA for the energy produced at a rate of $0.18/kWh based on the PPA. Table 3 summarizes the specifications of the three PV systems.

Table 3. Existing renewable DER at the HOST Park Research Campus

Name	Resource Type	Rated DC capacity (kW)	Rated AC capacity (kW)	Ownership	Proximity to critical loads
NELHA PV1	Ground-mounted PV	17.7	15	NELHA	Research Campus pumps
NELHA PV2	Ground-mounted PV	17.7	15	NELHA	Research Campus pumps
Keena Hana	Roof-top PV	37.95	34	PPA	Research Campus pumps
Hale Iako	Roof-top PV	130.68	120	PPA	Research Campus pumps

Capacity factor is a measure of how much energy is produced by a generating plant compared with its maximum output. It is measured as a percentage, generally by dividing the total energy produced during some period of time by the amount of energy the plant would have produced if it ran at full output during that time. The capacity factor for the PV systems is calculated using the following equation with the data collected from on-site PV meters:

$$PV\ Capacity\ factor\ (\%) = \frac{Energy\ delivered\ to\ the\ grid\ in\ a\ period\ of\ time}{Number\ of\ hours\ in\ the\ period\ \times\ Installed\ capacity} \times 100$$

From October 2019 to June, 2020, the NELHA owned ground-mounted PV systems, PV1 and PV2, had cumulative capacity factors of 19.33% and 17.49%, respectively. During that same period, the Hale Iako building rooftop PV system had a cumulative capacity factor of 22.05%. A capacity factor for the Keena Hana building rooftop PV system was not calculated for the full nine-month period due to issues with the metered data set for the months of November 2019 to February 2020. The Keena Hana PV system cumulative capacity factor over the remaining five months (October 2019, and March through June 2020) was 20.39%.

As a point of reference, using the National Renewable Energy Laboratory (NREL) PVWatts Calculator,[2] a production estimate for a typical fixed axis open-rack PV system in the HOST Park yields a capacity factor of 23%. The renewable energy production and capacity factor for the HOST Park PV systems will be updated and reported periodically as additional on-site data become available.

Table 4 shows the monthly and cumulative capacity factors for each of the PV systems at the HOST Park from October 2019 to June 2020. As shown in the table, the monthly capacity factors of the larger rooftop PV systems exhibit a more pronounced seasonal variation in energy production when compared to the smaller ground-mounted systems. This increased "seasonality" is a result of the non-optimal orientation of the rooftop PV systems as constrained by rooftop structure design. In contrast, the ground-mounted PV system is more optimally oriented, facing south with a panel tilt angle set to maximize sunlight exposure. Accordingly, the monthly capacity

[2] NREL's PVWatts calculator is available at https://pvwatts.nrel.gov/.

factors of the ground-mounted PV system remained relatively more stable over this period. However, while the ground-mounted system exhibited reduced seasonality, its lower capacity factor is attributed to the aged PV panels and their low designed efficiency (15%).[3] These factors will be considered in the design of microgrid solutions for the HOST Park.

Table 4. Monthly and cumulative capacity factor of existing PVs at the HOST Park

Month	PV1 15 kW (%)	PV2 15 kW (%)	Keena Hana 34 kW (%)	Hale Iako 120 kW (%)
Oct 2019	20.60	18.36	16.61	21.59
Nov 2019	19.71	17.42	--	19.55
Dec 2019	17.09	15.15	--	17.26
Jan 2020	17.92	15.87	--	18.35
Feb 2020	18.43	16.43	--	20.25
Mar 2020	18.73	16.95	18.42	21.67
Apr 2020	21.39	19.57	23.34	25.42
May 2020	19.24	18.09	23.14	25.17
June 2020	20.86	19.64	22.54	24.63
Cumulative	19.33	17.49	20.39	22.05

3.3 Planned renewable DER

In order to improve the resiliency and reduce the utility bills of the HOST Park, new renewable DER are scheduled to be installed in 2021. It is part of a microgrid demonstration project, and the new renewable DER will serve the 55” pump station. The microgrid demonstration project is funded in part by the Korean government and the State of Hawaii. Encored, Inc. leads this project in partnership with LG Electronics Inc., Seoul National University, Gwangju Institute of Science and Technology, Engie, Coast Energy Capital and HNEI. The research is focused on developing artificial intelligence to increase battery storage efficiency by 20% [2]. Upon completion of the research and demonstration of the microgrid technologies, ownership of all equipment will be transferred to NELHA by the end of 2026. The total project cost is estimated at 4 million US dollars. Detailed information regarding the new renewable DER is reflected in Table 5. The microgrid demonstration project is still in the design phase, and the DER is expected to be on-line by the end of 2021 [3].

3 Measurement of a solar panel’s ability to convert sunlight to usable electricity.

Table 5. Planned renewable DER at the HOST Park 55" pump station

Resource Type	Rated DC capacity	Rated AC capacity (kW)	Proximity to critical loads
Ground-mounted PV	500 kW	466	55" pump station
UPS	5 min @ 27 kVA	--	55" pump station
Battery	760 kWh/ 250 kW	--	55" pump station

A schematic of the project components is shown in Figure 4. In this figure, the resources in red indicate new planned resources.

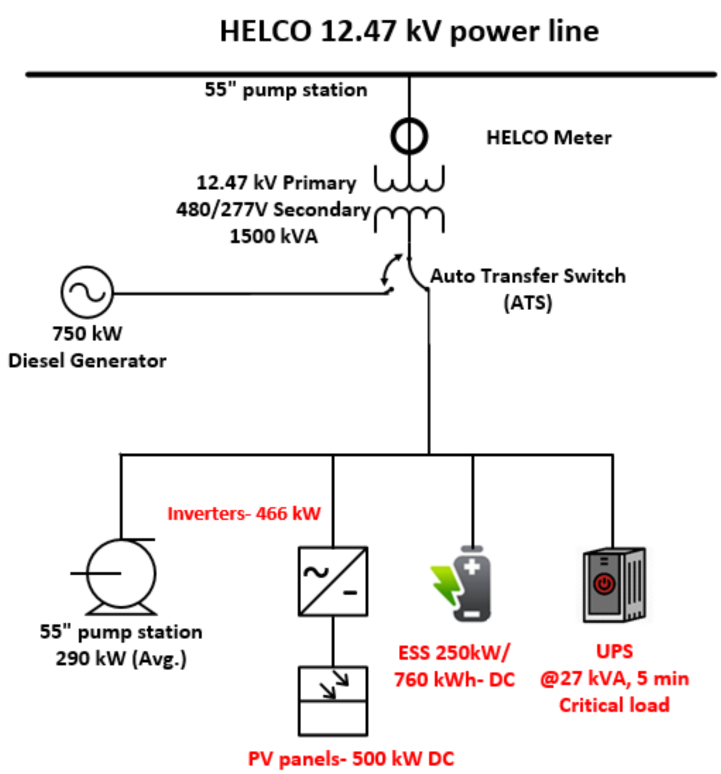

Figure 4. Single-line diagram of 55" pump station.
Planned new resources are written in red text.

The project includes installation of a 466 kW ground-mounted PV system (with PV panels rated at 500 kW DC) and a 250 kW / 760 kWh battery ESS. The average load at the 55" pump station was 290 kW in 2019, whereas the PV system is rated at 466 kW. Hence, the PV system is likely to produce excess energy during the daytime peak production, and the excess energy will be stored in the ESS. NREL's PVWatts Calculator estimates the annual energy production of a typical fixed axis open-rack PV system of equivalent rating to be approximately 940 MWh with an associated capacity factor of approximately 23%. The optimized use of the PV and ESS (assuming a 23% capacity factor) may supply approximately 37% of the total energy demand of the 55” pump station, at a maximum.

For reference, a summary of load at the 55” pump station based on data from the HELCO meter is shown below:

Total energy use in 2019:	2541.77 MWh
Peak demand:	501.36 kW
Occurred on:	Mar. 20, 2019 12:30 (see Section 4.1, Figure 7)
Average demand:	290 kW
Load factor:	57.87 ($\frac{\textit{Average demand}}{\textit{Peak demand}}$)

3.4 Existing advanced energy projects

The NELHA HOST Park is home to several advanced energy research projects such as HNEI’s hydrogen production, storage, and filling stations; and Makai Ocean Engineering Inc.’s Ocean Thermal Energy Conversion (OTEC) system. Based on feedback from NELHA and the objectives of these projects that are relatively small scaled and research focused, application of these energy resources for practical use in a prospective HOST Park microgrid operating in island-mode is not further considered. A brief status of the existing advanced energy research projects is provided here nonetheless for completeness.

HNEI Hydrogen Filling Station: This research project aims to have an operational hydrogen production and dispensing station to support a fleet of three hydrogen fuel cell electric buses (FCEB). HNEI has installed a 350 Bar (5,000 psi) hydrogen station to support the deployment of heavy-duty FCEBs at the HOST Park. The station is located in the Research Campus and has an electrolyzer that can produce 65 kg of hydrogen per day. The electrolysis of water at this hydrogen station uses approximately 65 kWh electricity per 1 kg of hydrogen production. The energy content of 1 kg of gaseous hydrogen is roughly the same as 1 gallon of diesel fuel. After the hydrogen is produced through polymer electrolyte membrane electrolysis, it is compressed to 450 psi (atmospheric pressure is 1 Bar or 14.5 psi at sea level) and stored in mobile hydrogen transport trailers that hold up to 102 kg of hydrogen [4]. The filling station has not been in operation since its initial testing and can add up to 250 kW of demand when operational, but the rate of hydrogen production and therefore the level of demand is adjustable.

Ocean Thermal Energy Conversion: OTEC is a process that produces energy by using the temperature difference between surface ocean waters and deep ocean waters. The United States Office of Naval Research (ONR) supported the development of a 105 kW demonstration OTEC plant at the HOST Park. This facility became operational in 2015 as a heat exchanger demonstration facility. NELHA has developed secondary uses of its ocean science facilities and its seawater system.

4 HOST Park load assessment

4.1 Energy consumption

To determine the current energy consumption and assess possible load trends, HNEI studied the HOST Park's energy data for the last five years at the five transformers described in Section 2 of this report. The energy data was acquired from the five HELCO revenue meters and recordings from the Supervisory Control and Data Acquisition (SCADA) system that is owned by NELHA. Figure 5 shows the net hourly average energy consumption at each of the five load sections for each month from 2015 through the end of 2019. The graph shows that the energy consumption at all five sites is relatively steady and has not dramatically increased over the last five years. The net load fell at the Research Campus at the end of 2019 due to the installation of the PV systems described in Section 3.2. NELHA foresees an increase in demand at the Research Campus of up to 250 kW once the HNEI's hydrogen filling station goes online; however, the level of production and therefore the increase in demand can be reduced and scheduled, to the PV production hours for example. NELHA also has 250 acres of developable land. However, the additional water demand and the associated increase in electrical demand due to pumping is difficult to estimate since this potential addition may be offset by a decrease in water usage from existing clients.

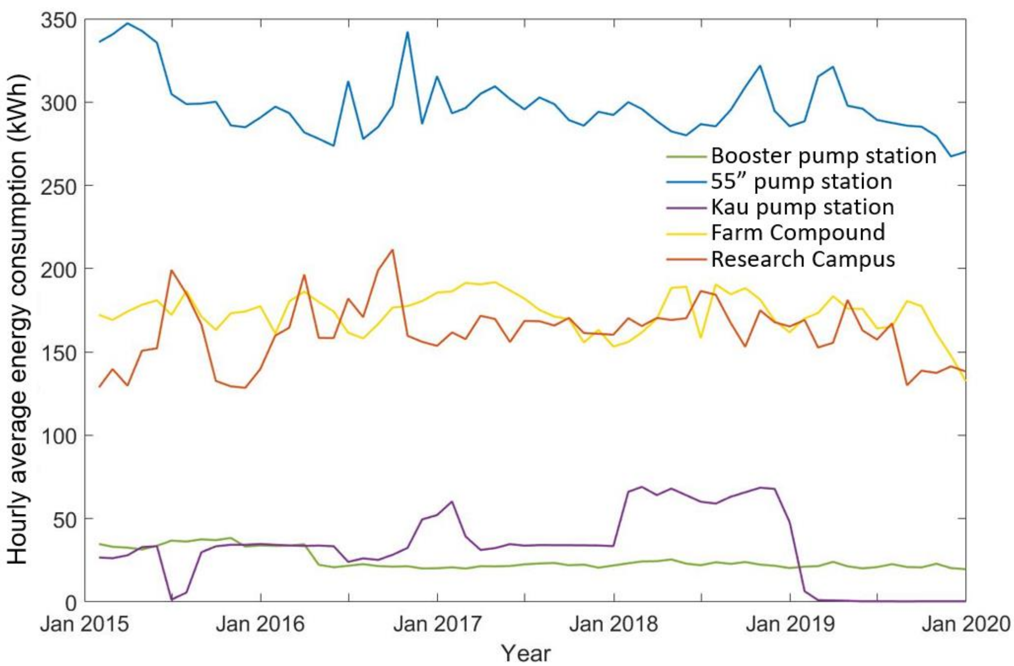

Figure 5. Average hourly net energy consumption.
The hourly net energy consumption has been averaged for each month.
The figure shows the data from January 2015 to end of 2019 in each load section.
The data is extracted with a 1-hour resolution from HELCO meter data accessed via its customer web portal.

Hourly net energy consumptions of the Research Campus in 2019 are shown in Figure 6. As discussed in Section 3.2, two PV systems were commissioned at the Research Campus in the second half of 2019. Sharp daily dips in Figure 6 show the production from PV systems "behind the meter" resulted in a net reduction in energy use at the Research Campus yielding reduced energy purchases from HELCO. Although the installed AC capacity of the PV systems combined is about 184 kW, the recorded PV data reflect a maximum coincident power generation being lower than the rated capacity. For example, the recorded maximum cumulative power generated by the three PV systems was about 149 kW in January 2020 and 162.8 kW in the year 2019, both data underrunning the maximum installed AC capacity of 184 kW. As discussed in Section 3.3, the main reasons for the underperforming PV energy production are the low efficiency and aged PV panels for the ground-mounted PV system and the suboptimal orientation of PV panels for the newer rooftop systems.

As shown in Figure 6, there were two abnormal rises in load for a short duration of time in January 2019. Upon investigation, it was determined that these peaks in energy use and power demand resulted from research tests performed by a tenant of NELHA, namely HNEI, at its advanced energy hydrogen filling station. The incremental and one-time cost of additional energy consumed during these events were rather small; however, the impact of these types of anomalous events on recurring 12-month bills would be worth reviewing closely to explore the opportunity for the event and demand charge bill impact management.

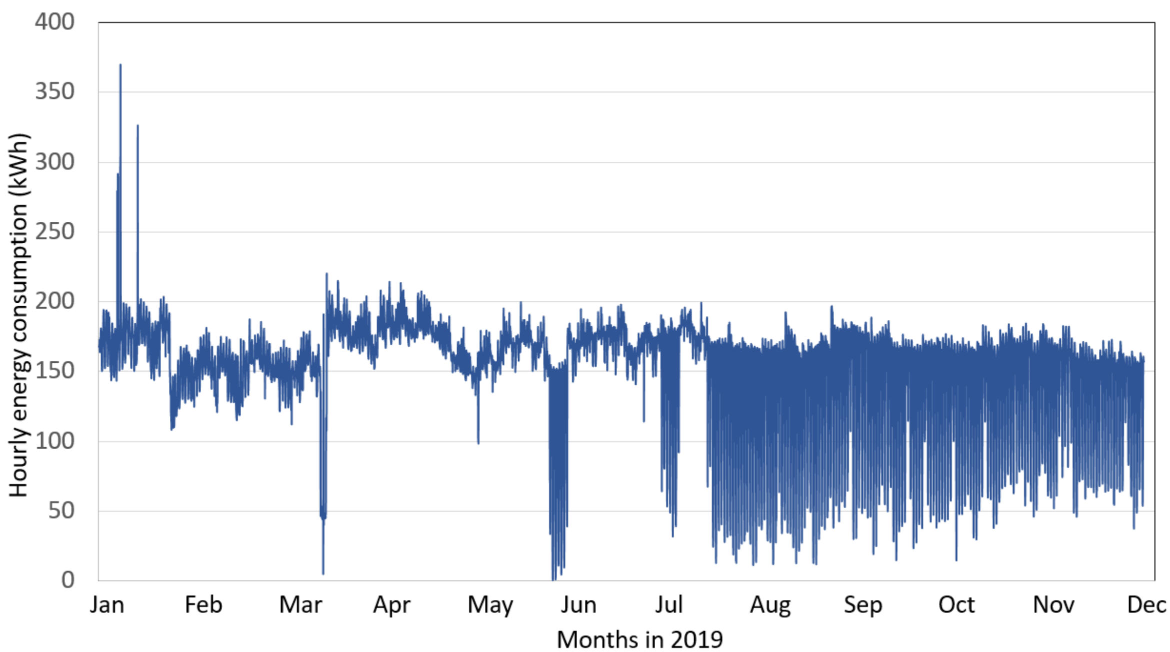

Figure 6. Hourly net energy consumption of the Research Campus in 2019.
The data is sourced from the HELCO meter customer web portal.

Figure 7 shows the hourly energy consumption of the 55” pump station for the year 2019. The data was collected from the HELCO meter. Similar to the abnormal peak load event observed in the Research Campus hourly net energy consumption, an abnormal rise for a short duration in the 55” pump station demand is observed in March 2019 in Figure 7. Upon investigation, it was determined that NELHA shifted all of its pumping load at the Research Campus to the 55” pump station for an approximately 48-hour period to accommodate electrical connection upgrades for installation of rooftop PV systems at the Research Campus on March 19th. Again, the recurring 12-month bill impact resulting from peak demand events such as this occurrence is notable and a worthy candidate for closer review. Possible mitigations via assets deployed as part of a microgrid solution may be available.

It is also observed in the data that the HELCO meter recorded zero consumption for 45 minutes on August 14th due to a power outage (see Section 4.8 for further discussion on power disruption events). Finally, on June 25th, September 24th, October 8th, October 29th, and November 9th, power demand and energy consumption at the 55" pump station was significantly reduced from its average for a few hours due to periodic shut down of one or more of its station water pumps.

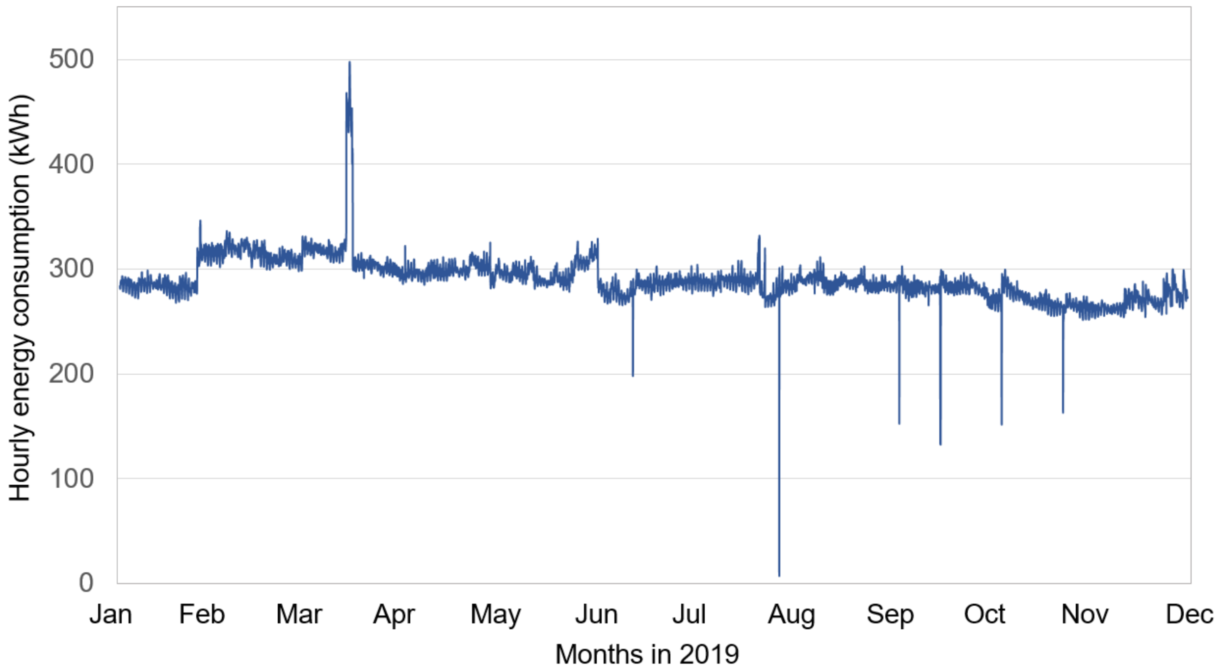

Figure 7. Hourly energy consumption of the 55" pump station in 2019.
The data is sourced from the HELCO meter customer web portal.

In Figure 8, the HOST Park's monthly energy consumptions in 2019 were evaluated for each of its five primary load sections to determine the extent of seasonal variation in energy use. The 55" pump station monthly energy consumption was fairly consistent and did not exhibit significant seasonal variation. It is noted that energy consumption for the month of March was unusually high due to an atypical two-day transfer of Research Campus pumping loads. Aside from the month of March, the monthly energy consumption varied at maximum 9% from the average monthly energy consumption.

For the Research Campus, Farm Compound, and Booster pump station, the monthly energy consumptions for each load section varied at maximum 13.2%, 19.3%, and 14.7% from their average monthly energy consumption across 2019. An estimate of the gross monthly energy consumption for the Research Campus is shown by the dotted red line in Figure 8. The estimation was derived by adding the total monthly energy delivered by the existing PV plants and the recorded net monthly energy consumption of the Research Campus.

The monthly energy consumption for the Booster pump station is highly consistent throughout the year. For the Kau pump station, the January 2019 monthly energy consumption was recorded at

4,034 kWh; however, the total annual consumption was insignificant, as the monthly energy consumption at the Kau pump station remained near zero in all months thereafter due to the retirement of station loads. Overall, the seasonal variability in energy consumption was not significant at the HOST Park.

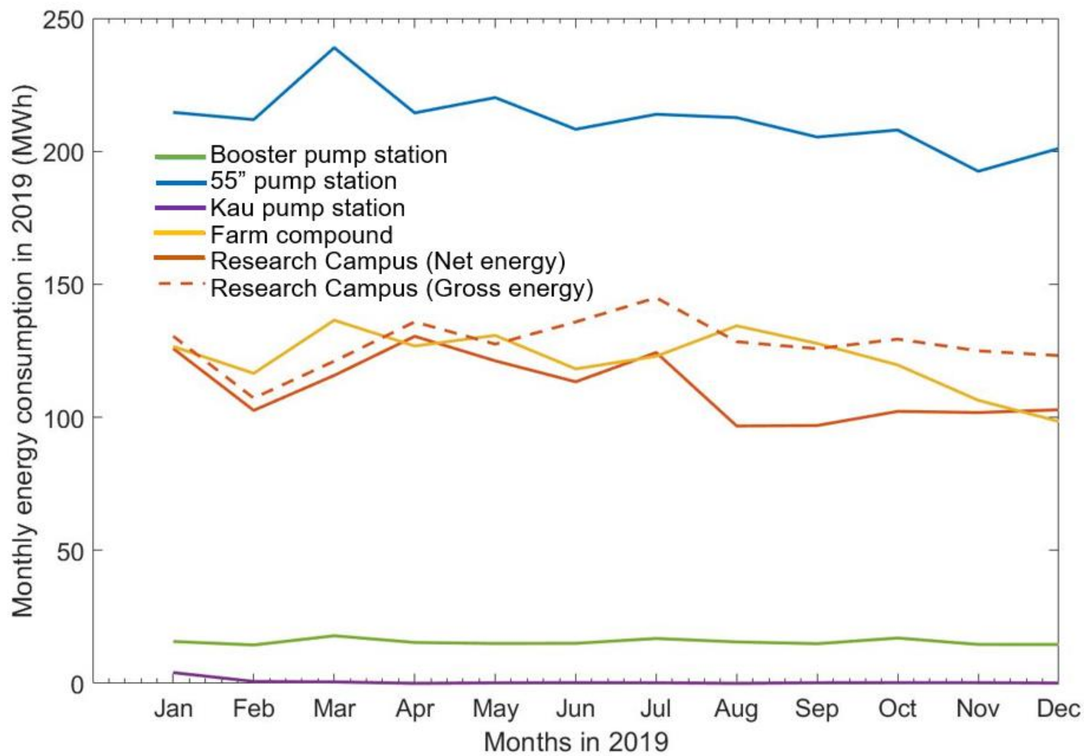

Figure 8. Monthly energy consumption of the HOST Park in 2019.
The dotted red line shows the Research Campus gross load profile, derived as the sum of the energy consumption from HELCO and PV system production. The data is sourced from the HELCO meter customer web portal and HOST Park SCADA system.

4.2 Impact of increased PV additions on the Research Campus load profile

As discussed in Section 3.2, all existing PV systems at the HOST Park are installed at the Research Campus. Figure 9 compares average power demand, recorded in 15-minute intervals, captured by the HELCO revenue meter in the selected weeks in 2018 and 2019. The weeks were selected approximately 12 months apart to minimize the potential impact of seasonal variability on the comparison of the selected demand profiles. The intent of this comparison is to visualize the hourly and daily impact of the added PV systems on the net load profile of the Research Campus over the course of an entire week. The net load profiles of the orange and blue curves represent the power demand of the Research Campus served by HELCO. The orange curve shows the net load profile for a week in November 2018 when only NELHA's ground-mounted PV system was in operation. The blue curve shows the net load for a week in November 2019 when all three PV systems were in operation. The diminishing power and energy supply from HELCO as a result of increased behind-the-meter PV penetration is readily evident in the figure.

The blue curve also reveals that while an appreciable amount of the daytime energy needs of the Research Campus are now served by the three existing PV systems, significant opportunity exists for additional PV to be sited at the Research Campus to serve load both during the day and at night if combined with an ESS. Deployment of additional PV resources combined with an ESS is a foundational element for a future microgrid deployment and will be closely evaluated in later phases of this project.

Finally, there also appears to be some moderate reduction in the daily peak demand served by HELCO as a result of the significant reduction in power demand during most of the daylight hours, where gross demand appears to otherwise be at its highest. A consistent daily peak demand reduction provides the potential for some cost savings due to a reduced demand charge on the HELCO bill over time. Additional PV combined with an ESS at the Research Campus site should present more significant opportunity for demand charge savings in the future.

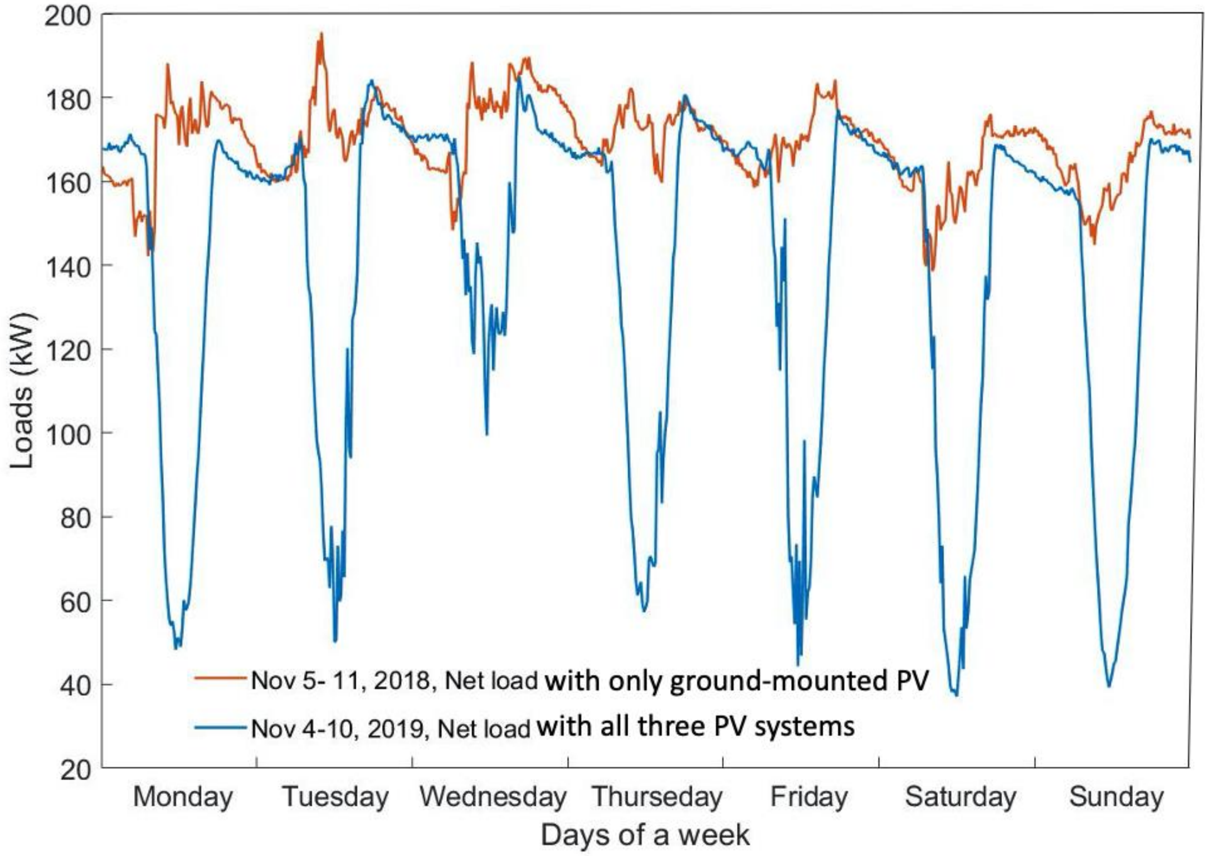

Figure 9. Impact of Research Campus PV additions.
Both the red and blue lines show the 15-minute interval average power demands for selected weeks.
The data is sourced from the HELCO meter customer web portal.

4.3 HOST Park hourly load variation over a day

To analyze the hourly load variation over a day at the HOST Park, the load patterns of two selected days in 2019 for each load section, except for the inactive Kau pump station, were plotted in Figure 10. Each day represents the day with the highest or lowest energy consumption over a 24-hour period at each load section. Apart from the Research Campus data, the high/low energy consumption days for the other three sites were selected from the entire year of 2019. The blue curve shows the load pattern on the highest energy consumption day, and the orange curve depicts that of the lowest energy consumption day.

For the Booster pump station load shown in Figure 10(a), the daily load pattern is relatively flat over the 24-hour period with a small step increase of approximately 6 kW in demand from night to day. The small step change appears to be associated with the daily cycling of pumping loads on a scheduled basis.

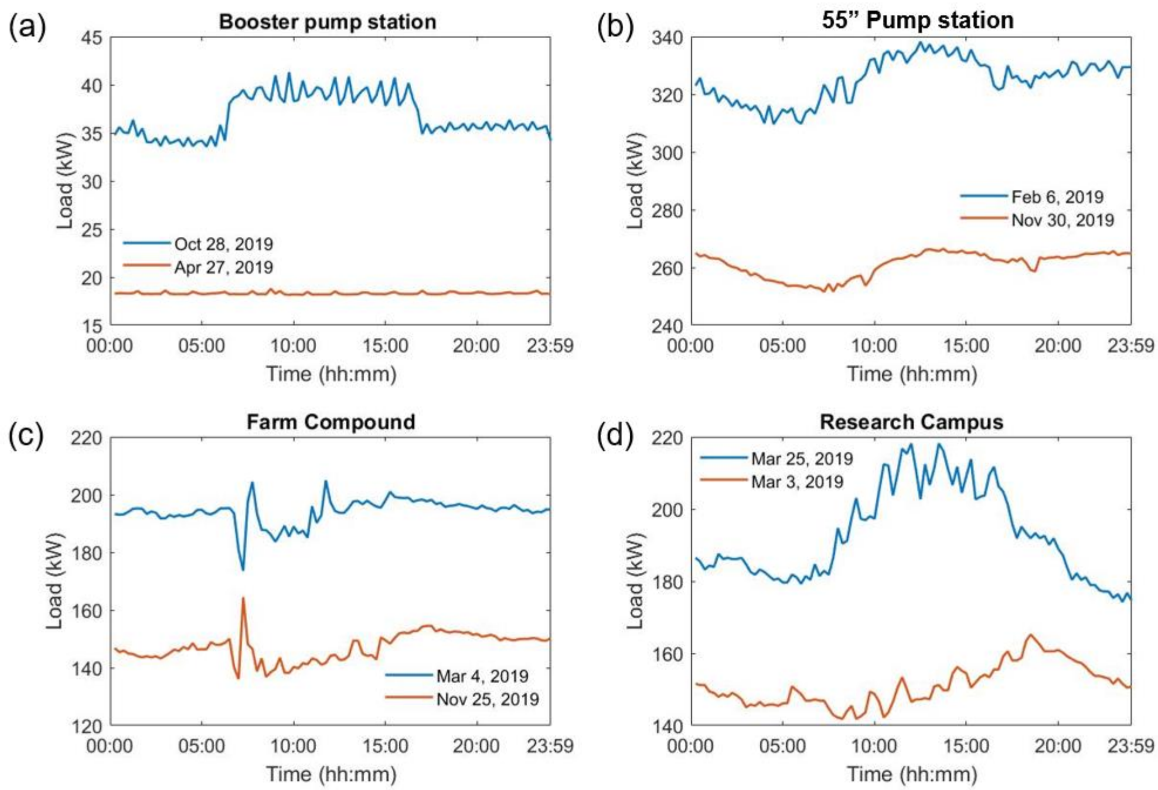

Figure 10. Hourly demand variations at load sections for select days in 2019.
The data is sourced from the HELCO meter customer web portal and HOST Park SCADA system.

The daily load pattern at the 55" pump station, shown in Figure 10(b), exhibits a fairly smooth transition from its lowest load level in the early morning hours, steadily ramping up until reaching its highest demand at mid-day, followed by a slight reduction in the afternoon while holding this load level into the evening, and then steadily ramping down after midnight to its lowest load point again the following morning. The largest daily load ramp that stretches from the early morning low to mid-day high demand is approximately 30 kW, which is less than 10% of the mid-day peak demand. After the planned addition of the renewable DER with the microgrid demonstration project described in Section 3.3, the new net load pattern for the 55" pump station is expected to be dramatically altered with significantly less energy purchased from HELCO in the day and a reduced level of energy purchased at night as a result of the PV and battery ESS installation.

For the Farm Compound, the hourly load profile exhibits little change in demand for day hours compared to evening hours. However, there is a consistent and pronounced drop in demand, followed immediately by a sharp rise, and then another abrupt drop in the morning hours between approximately 7:00 and 8:00. Aside from these relatively short spikes in load which appear to be driven by regularly scheduled activities at that time, the hourly load profile is relatively consistent over the daily load cycle.

Lastly, for the Research Campus load section plotted in Figure 10(d), the high/low energy consumption days were selected from the data from January to May 2019, before the two PV systems (170 kW) contracted under PPA were commissioned, to best capture a contemporary view of near gross load demand for this section. The load profile of the Research Campus exhibits the greatest recurrent daily variation in demand in comparison to the other three load sections, with the day load being appreciably higher than the evening demand. As evidenced in the blue curve, the demand in the day can exceed the evening demand by as much as 40 kW, which is an increase of more than 20% above the evening load level. Daily load profiles that exhibit this shape with higher day loads compared to evening loads are good candidates for PV installation due to the higher coincidence of demand and solar energy production. As shown in Figure 9 above, the net load shape after accounting for the energy production of all three PV systems still presents significant opportunity for the installation of additional PV and an ESS at the Research Campus site.

4.4 Weekday and weekend energy consumption

Figure 11 presents the daily average energy consumption during weekdays and weekends for the 55” pump station, the Research Campus, and the Farm Compound for each month in 2019. The loads in these three load sections consumed 96.5% of the total energy of the five load sections in 2019. The difference for the Research Campus, while larger than the other two sites, had a weekday average energy consumption for each month exceeding that on the weekend by only 6%.

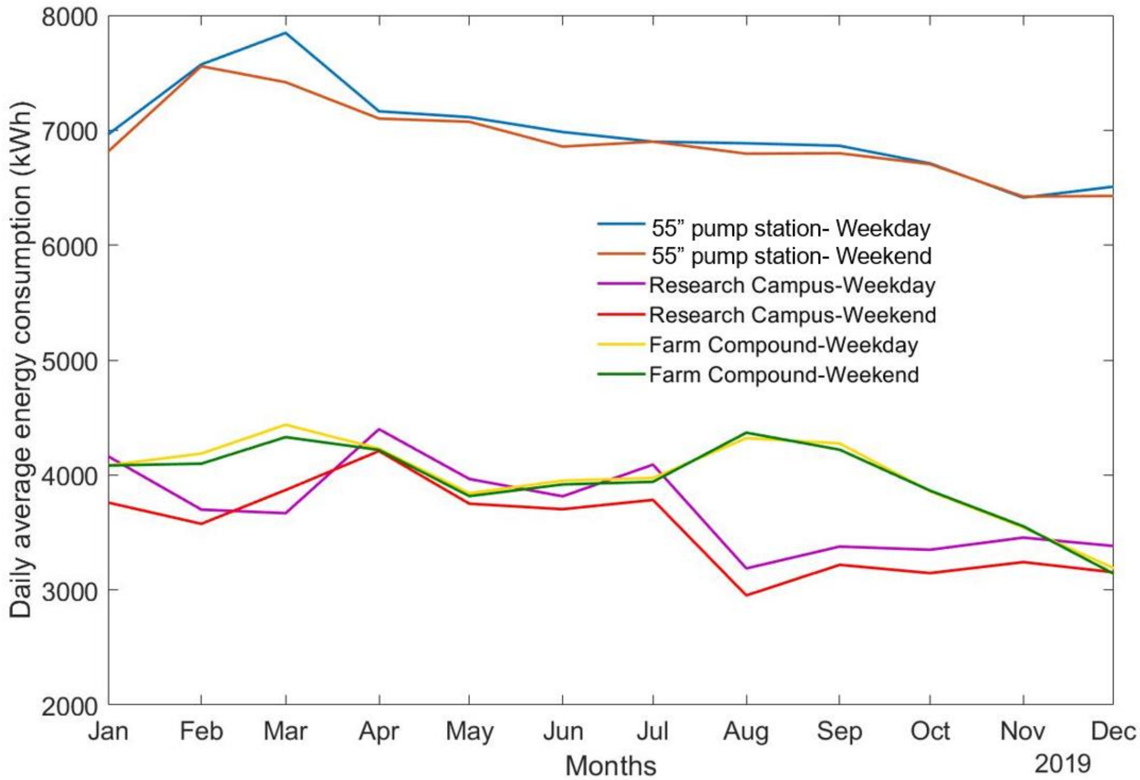

Figure 11. Daily average energy consumption on weekdays and weekends in 2019. The data reflect three major load sections' daily average energy consumptions. The data is sourced from the HELCO meter customer web portal.

4.5 Peak demand

One of the potential benefits that may be derived from resources integrated in a microgrid solution is peak demand management to reduce the utility demand charge when operating in grid-connected mode, thus reducing the monthly electric bill. The peak demand for NELHA's three most power and energy intensive load sections at the HOST Park was evaluated over the period from 2015 to 2019. Figure 12 plots the monthly 15-minute peak demand for the 55" pump station, the Research Campus, and the Farm Compound for those years.[4] It is readily observed that the monthly peak demand for the Farm Compound load center exhibits a relatively smooth and recurring load shape. It displays seasonal variation characteristics with approximately 50 kW annual variation, and thus the opportunity for bill reduction associated with demand charge management is limited.

[4] The data for the Farm Compound is not available for 2015.

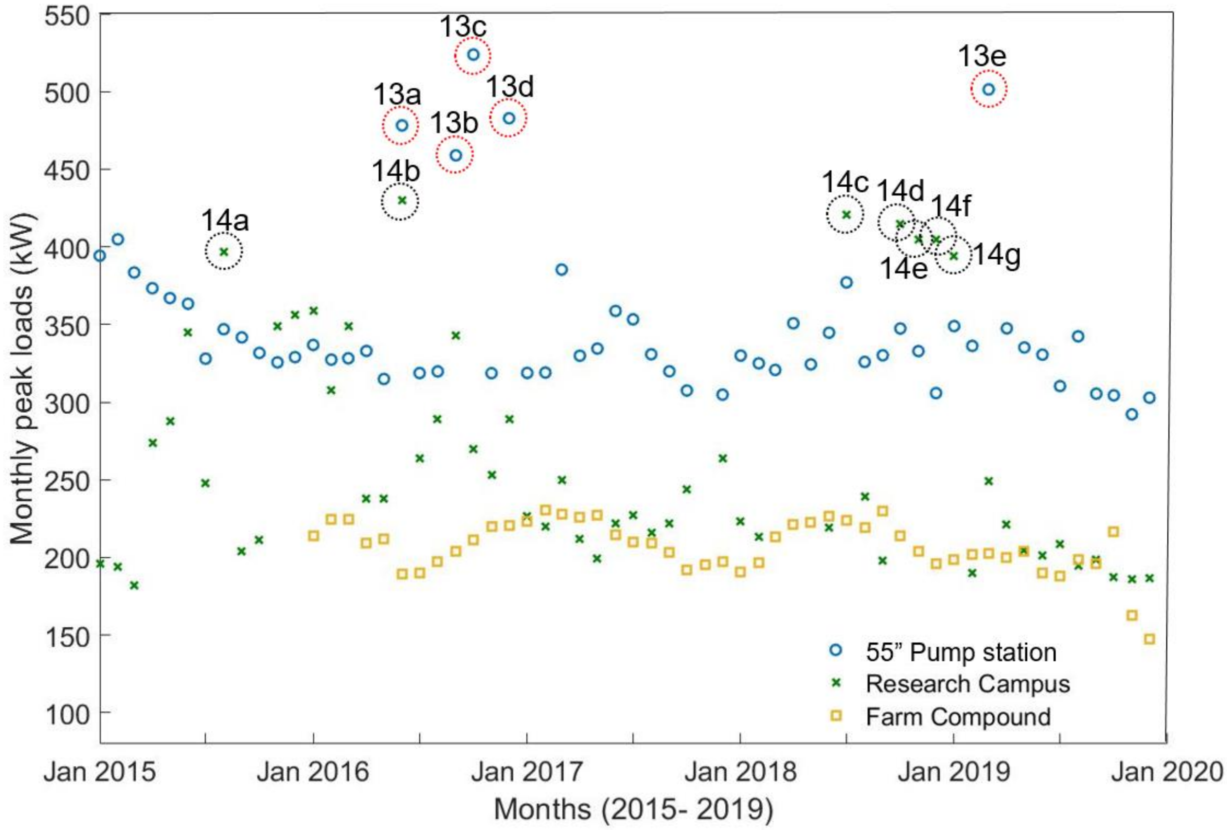

Figure 12. Monthly peak loads at three major load sections from 2015 to 2019.
The highest outlier peak load events are marked with dotted circles.
Red dotted circles are events at the 55” pumping station, and black dotted circles are events at the Research Campus.
The data is sourced from the HELCO meter customer web portal.

However, several instances of unusually high peak demand can be identified in Figure 12 for both the 55” pump station and the Research Campus load sections, with the highest peak demand events for each of these load sections marked with red and black dotted circles, respectively. These events, if they can be effectively managed, present increased opportunity for demand charge bill reduction. To analyze these circled peak demand events, the date, time, and duration of each of these events are plotted in Figure 13 for the 55” pump station, and Figure 14 for the Research Campus.

As seen with the red dotted circles in Figure 12, there were four uniquely high peak load events for the 55” pump station in 2016 that were greater than 450 kW, far exceeding the otherwise “normal” monthly peak load that ranged between approximately 310 and 340 kW. These peak load events occurred during the 105 kW OTEC trials. The trials required all excess capacity from NELHA’s pump stations to achieve the 105 kW production goal. In Figure 13(a), a peak demand event of 478 kW occurred on June 19, 2016 and the next highest peak for the month of June was recorded at 434 kW. As shown in Figure 13(b), two peak load events occurred in September, each about 460 kW, with the first event recorded on September 28, 2016 and the second on September 30, 2016. Figure 13(c) shows three peak load events of about 520 kW in magnitude occurring on October 3, 5, and 6, 2016. The peak load event that started on October 6, 2016 was very long in duration, lasting about 25 hours. In Figure 13(d), two peak load events occurred in

December, each about 480 kW, with the first event recorded on December 7, 2016 and the second on December 13, 2016. Reviewing the plots in Figures 13(a) to 13(d), it appears that the pumping load for the 55" pump station was very inconsistent, with wide ranging high and low demand levels. Such high variability in a load profile is generally not desirable financially and results in higher monthly electric bills as peak demand events will have a year-long demand charge impact on the bill. It is noted that the demand peaks in the 15-minute interval HELCO meter customer web portal data do not match the monthly demand shown on the HELCO bills. For example, a 460 kW peak demand is shown on June 19, 2016 in the web portal data and the demand on the June 28, 2016 HELCO bill was 309.6 kW. A 520 kW peak demand is shown on October 28, 2016 in the web portal data and the demand on the October 28, 2016 HELCO bill was 633.6 kW. It may be advisable for NELHA to inquire with HELCO to explain the discrepancy.

However, much of the load variability experienced in 2016 no longer existed in 2019. Figure 13(e) reveals that the variability in the pumping load at the 55" pump station has been greatly stabilized and settled just above 300 kW for most of March 2019. As described in Section 4.1 above and noted in Figure13(e), however, a one-time peak demand event occurred on March 19th when NELHA was required to shift all of its pumping load at the Research Campus to the 55" pump station for approximately 48 hours to accommodate electrical connection upgrades for its new PV systems. This long spike in peak demand reaching as high as 500 kW and continuing at over 450 kW for more than 14 hours set the demand charge ratchet on the electric bill for the ensuing 12 months. A bill impact analysis of this event is provided in Section 4.6. Future energy resources provided as part of a microgrid solution located behind the 55" pump station meter offer opportunity for some relief from such events should they occur in the future.

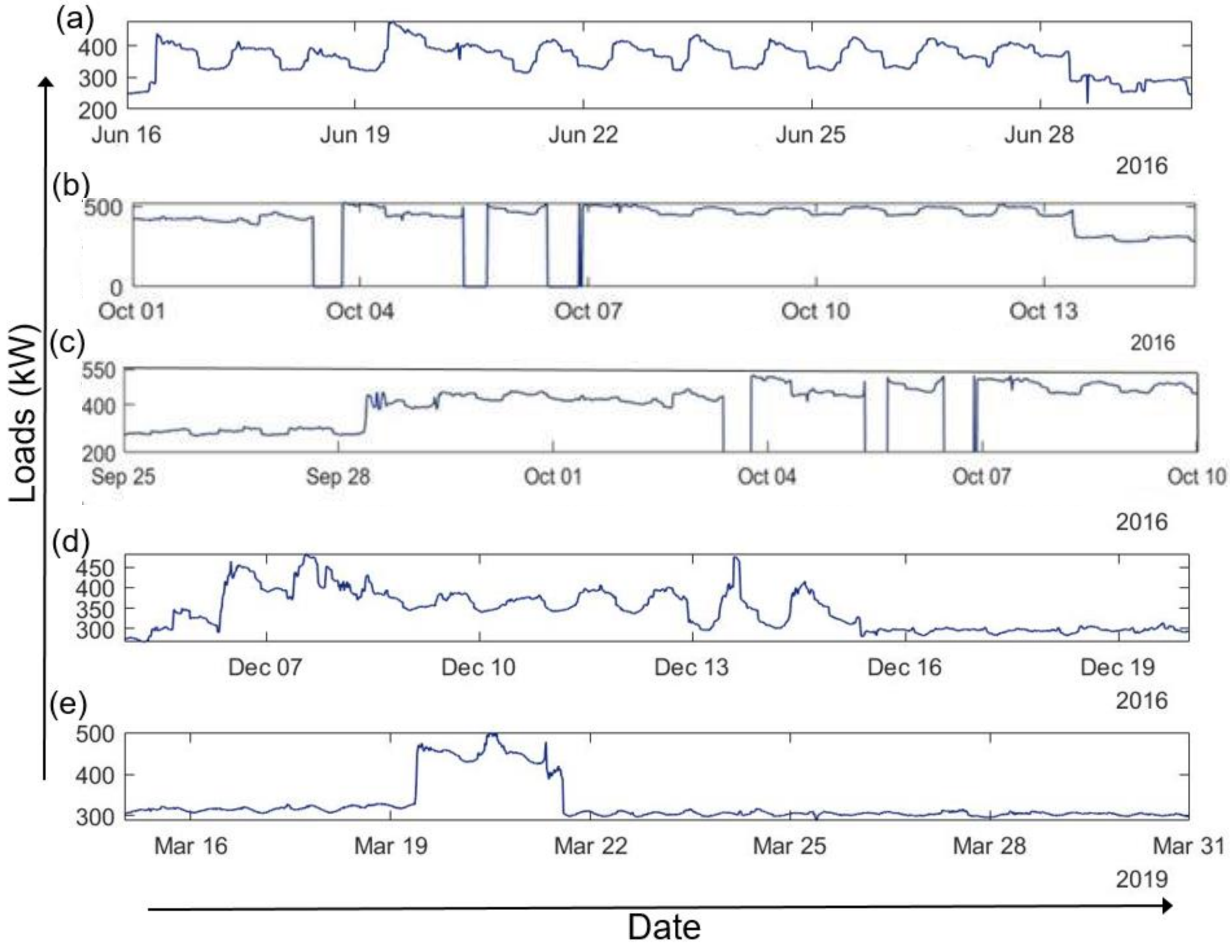

Figure 13. Peak demand events recorded at the 55" pump station from 2015 to 2019.
The events are identified by the red dotted circles in Figure 12.
The 15-minute interval data is sourced from the HELCO meter customer web portal.

Figure 14(a) reveals that a 385-kW peak demand event lasted for 15 minutes at the Research Campus on June 14, 2015. In Figure 14(b), the Research Campus peak demand occurred on June 16, 2016, spiking to 430 kW for 45 minutes. In Figure 14(c), two peak load events above 400 kW were observed, the first occurring on July 11, 2018 and lasting for about one hour, and the second on July 12, 2018, lasting about six hours. Figure 14(d) shows three peak demand events over 400 kW each on October 25, 29, and 30, 2018, with durations of 1 hour 15 minutes, 1 hour 30 minutes, and 2 hours, respectively. In Figure 14(e), two peak events are identified, each about 400 kW, occurring on November 14 and 30, 2018 for durations of 2 hours and 30 minutes, respectively. Figure 14(f) reveals one spiky 400 kW peak demand event on December 11, 2018 lasting less than 30 minutes. Lastly, Figure 14(g) shows multiple demand spikes of approximately 400 kW on January 7, 8, and 14, 2019, with durations ranging from 15 minutes to an hour.

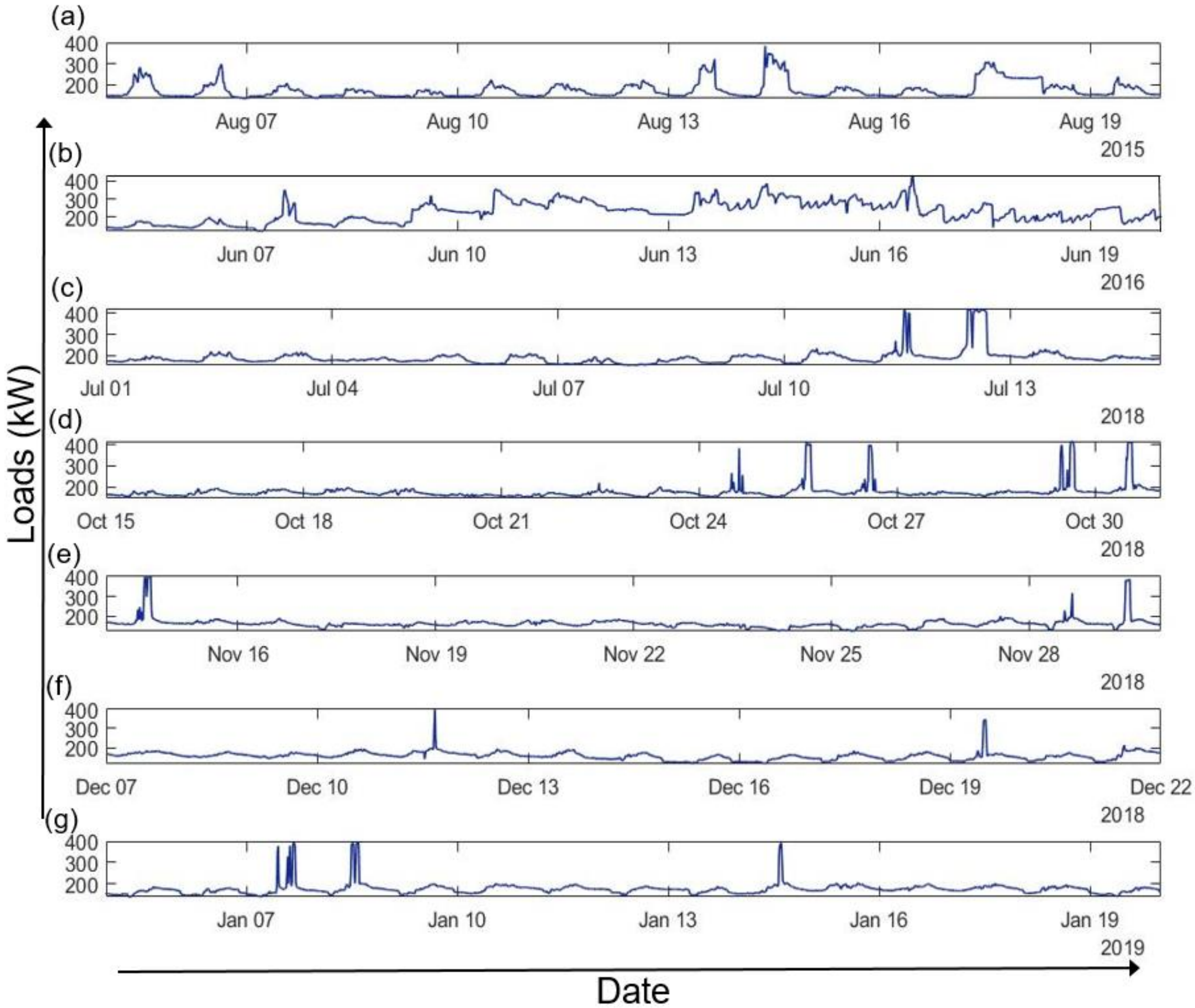

Figure 14. Peak demand events recorded at the Research Campus from 2015 to 2019.
The events are identified by the black dotted circles in Figure 12.
The 15-minute interval data is sourced from the HELCO meter customer web portal.

Generally, the peak demand at the Research Campus was more variable and less consistent in the years preceding 2018. From 2018 forward, the “normal” peak demand appears to be managed for the most part; however, it is subject to occasional large spikes in demand that resulted in significant increases in the demand charge on the Research Campus electric bill for the ensuing 12 months.

4.6 Billing

The electricity consumption of the loads managed by NELHA were measured at the five transformers identified in Figure 3. Table 6 lists these HELCO meters and their rate schedules.

Table 6. List of HELCO meters serving NELHA load sections in the HOST Park

Load sections	Meter ID	Customer ID	Rate schedule in 2019
Booster pump station	H202014332094	NELHA-BPS3	J
55” pump station	H202010175018	NELHA-55” PUMP STN	P
Kau pump station	H202014320701	NELHA-Kau PUMP WARM	J
Farm Compound	H202014127676	NELHA-FARM COMPOUND	P
Research Campus	H202010637868	NELHA-RES CAMPUS	J

The 55” pump station, Research Campus, and Farm Compound consume most of the total energy used by NELHA, with the respective stations’ usage being 45.9%, 24.1%, and 26.5% of NELHA’s overall energy consumption. The remaining 3.5% is consumed at the Kau pump and Booster pump stations. Among the five HELCO meters identified in Table 6, the 55” pump station and the Farm Compound were billed according to the rate schedule P and the others were on schedule J in 2019. The monthly peak demand shown in Figure 12 reveals that the demand at both the Research Campus and the Farm Compound are close to the 200 kW threshold between Schedule P and Schedule J.

Schedule P applies to large power services and to customers with a demand equal to or higher than 200 kW for 15 minutes within the previous 12 consecutive billing months. The Schedule P tariff includes a customer charge of $450, a demand charge of $25/kW, a non-fuel energy charge of 6.2243 ¢/kWh, and a power factor adjustment that is discussed in more detail at the end of this section. Schedule J applies to energy loads exceeding 5,000 kWh per month or 25 kW of demand three times within twelve months, but which are less than 200 kW. The Schedule J tariff includes a customer charge of $69, a demand charge of $13/kW, a non-fuel energy charge of 9.6488 ¢/kWh, and power factor adjustment.

As noted in Section 4.1 and 4.5, the Research Campus had anomalous peak load events in January 2019 arising from “one-off” research tests being conducted by a HOST Park tenant in cooperation with NELHA. This anomalous peak demand is nearly double the nominal peak demand of approximately 200 kW for the remainder of 2019. The Research Campus was above the 200 kW threshold in 2019 and years prior; however, it has not reached the 200 kW demand level since the addition of the rooftop PV systems.

Similarly, the 55” pump station had an anomalous peak load event starting on March 19, 2019 when NELHA shifted all of its pumping load at the Research Campus to the 55” pump station for close to 48 hours to accommodate the electrical connection of the rooftop PV systems at the Research Campus. This caused an increase in demand of approximately 150 kW.

The bill impact of these anomalous peak events was significant. The monthly demand charge on the Schedule J and Schedule P electric bills is based on the peak demand of the current month or the average of the peak demand of the current month and the highest peak demand in the past 12 months, whichever is higher. For the Research Campus, an increase in demand from 250 kW to 400 kW, at $13/kW, cost approximately $9,700 in 2019. For the 55" pump station, an increase in demand from 350 kW to 500 kW, at $25/kW, cost approximately $17,500 in 2019. Since these were planned events, there is an opportunity for significant savings in managing these types of peak events by utilizing other energy resources, such as batteries or portable generators, to supply the additional power needed during these relatively brief events.

An analysis of the difference between the application of Schedule J and Schedule P tariff rates for the Research Campus shows that the higher customer and demand charge and lower non-fuel energy charge of Schedule P would have added a total of approximately $3,700 to the bill for 2019 due to the anomalous peak event. However, if the maximum demand were kept to the typical 250 kW, then the Schedule P rates would have reduced annual costs by approximately $5,200. If the demand were further managed to 200 kW each month, the savings under Schedule P would be approximately $12,400 annually. With the peak demand for the Research Campus close to 200 kW, an energy use strategy that manages peak demand to just above 200 kW such that the Research Campus qualifies for the Schedule P rates, would provide significant electric bill savings over the course of a year.

Another bill impact consideration is the power factor adjustment, especially when adding renewable DER behind the meter. The power factor adjustment assesses Schedule P and Schedule J customers a credit or additional charge to their bill based on the customer's average power factor being greater or less than 85% for the month. Figure 15 below provides a graph of the 15-minute power factor measurements for the Research Campus for 2019. The graph shows that when the large rooftop PV systems were producing power at a unity power factor, the power factor measured at the meter was reduced significantly.

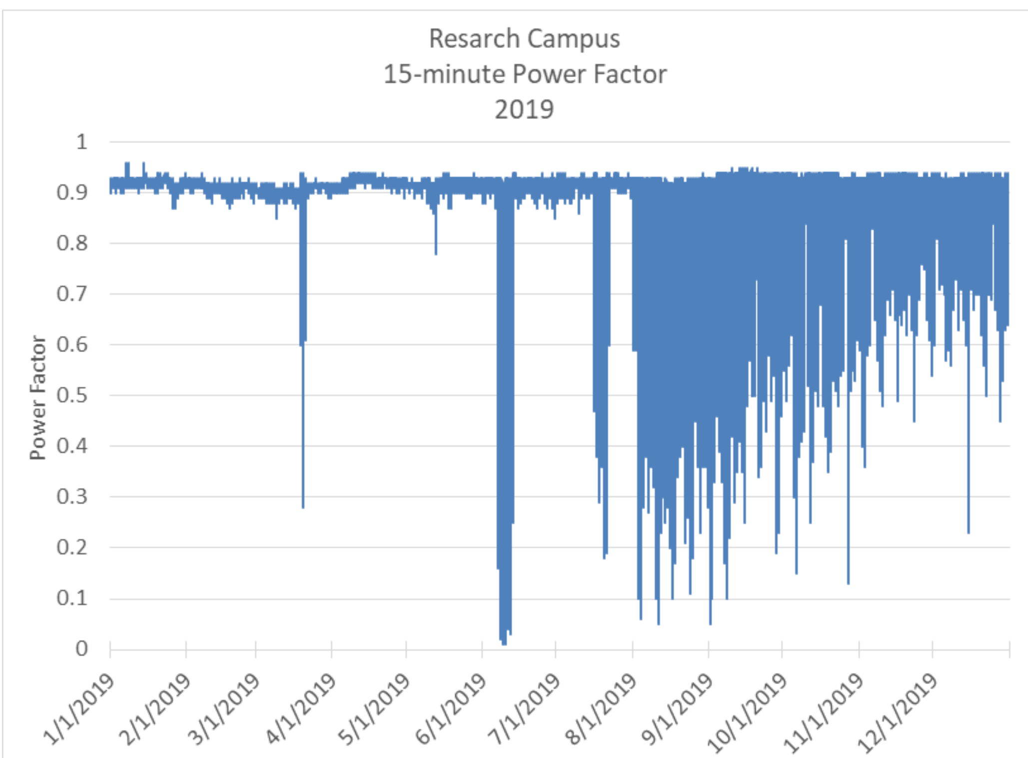

Figure 15. 15-minute power factor data from the HECO meter data portal.

The average power factor is calculated using the total kWh and total kVARh measurements per billing period. The power factor adjustment rate is calculated as [(85 - average monthly power factor percentage) x 0.10%]. The sum of the non-fuel energy and demand charges as well as 10.244 cents per kWh are multiplied by the power factor adjustment rate to determine the power factor adjustment applied to the bill. For example, the average power factor for the 55" pump station is normally 98%. The August 2019 bill for the 55" pump station had a non-fuel energy cost of $12,822.06, a demand charge of $10,545, and an energy consumption of 206,000 kWh. Therefore, the power factor adjustment applied to this bill is calculated as shown in the equation below. Since the power factor is greater than 85%, the power factor adjustment is a credit to the bill.

$$\big((85-98)*0.001\big)*\left(\$12{,}822.06+\$10{,}545+\left(206{,}000\,kWh*\frac{\$0.10244}{kWh}\right)\right)= -\$578.11$$

Since PV generation is variable and only occurs during the day, the monthly average power factor varies less dramatically than the 15-minute power factor measurements. The monthly average power factors for the Research Campus, 55" pump station, and Farm Compound for the two-year period from May 2018 to April 2020 are shown in Figure 16.

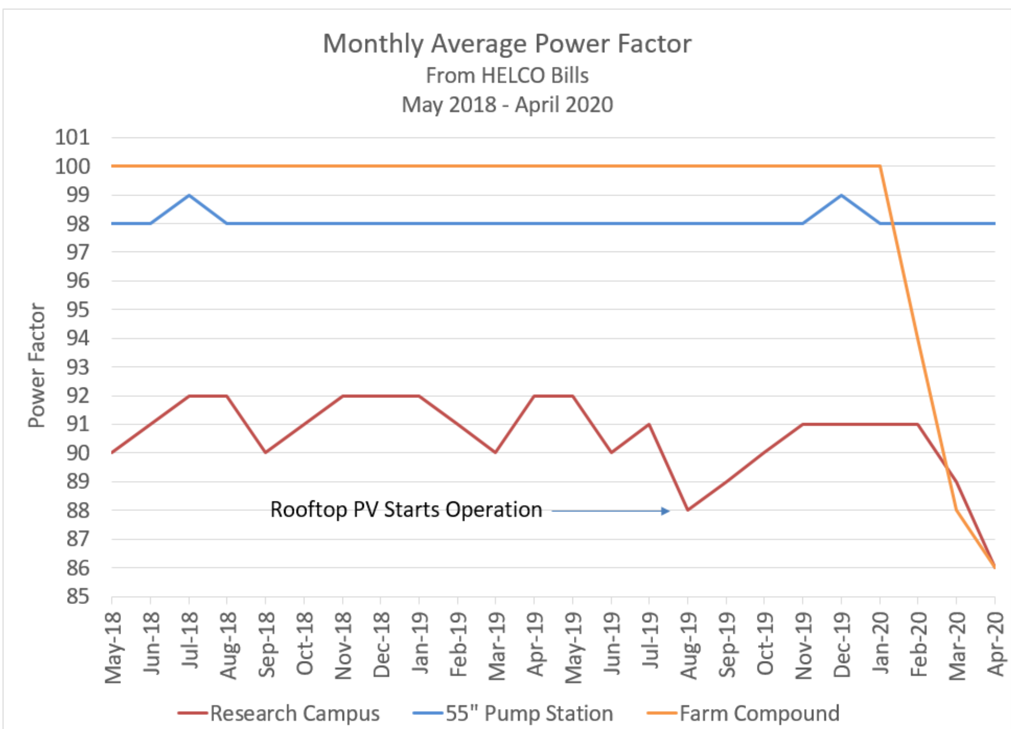

Figure 16. Monthly average power factor for the three major load sections.
Each line represents the monthly average power factor for the Research Campus, 55" pump station, and Farm Compound.

Figure 17 below shows the power factor adjustment credits on the HELCO bills for the two-year period from May 2018 to April 2020 for the Research Campus, 55" pump station, and Farm Compound. Figures 16 and 17 show that there was a reduction in the power factor and power factor adjustment credit for the Research Campus that correlated with the addition of the PV systems in August 2019. However, the overall dollar impact is not large due to the averaging of the power factor and the reduction in demand and energy usage with the PV in operation. Figure 16 also shows the result of a meter change at the Farm Compound in February of 2020 where the power factor is reduced from the constant 100% in the previous months to 88% in March and then 86% in April of 2020. The original meter did not record kVARh. This meter change resulted in a significant reduction in the power factor adjustment credit as shown in Figure 17.

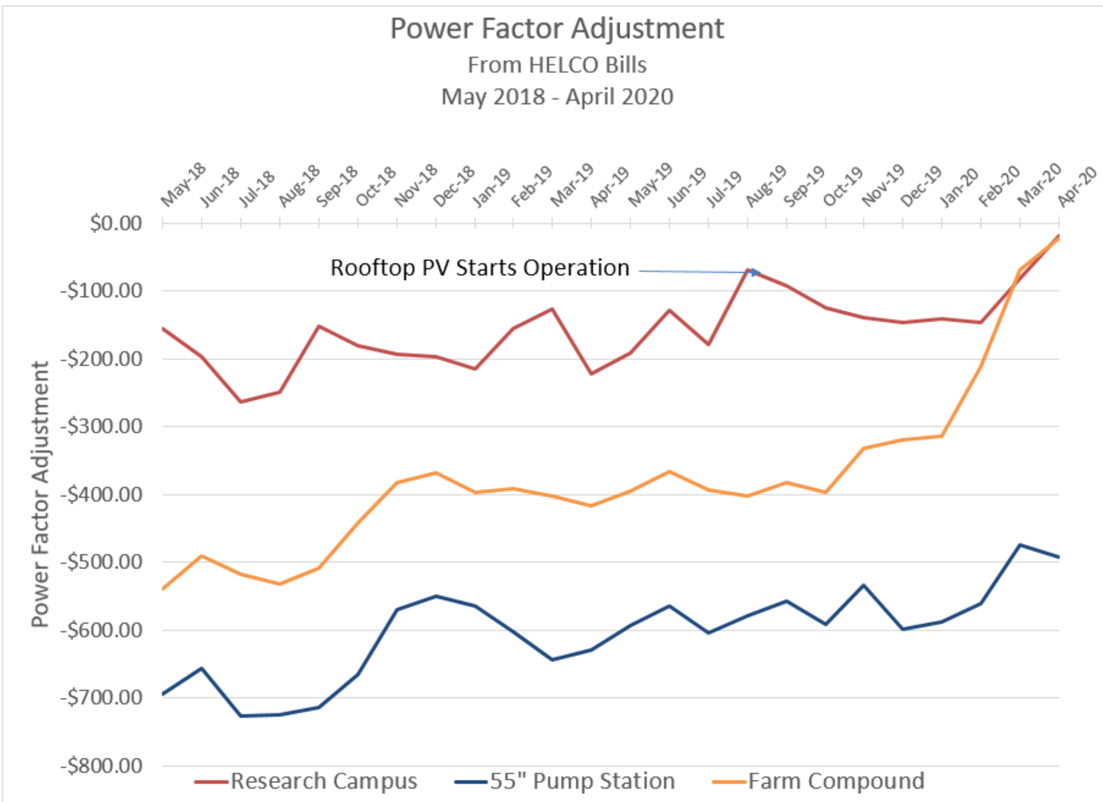

Figure 17. Power Factor Adjustment for the three major load sections
Each line represents power factor adjustment for the Research Campus, 55" pump station, and Farm Compound.

Figure 18 considers the impact of the addition of a large (500 kW) PV and battery system on the power factor adjustment credit for the 55" pump station load. A PV production estimate for a 466 kW ground-mounted PV system (with PV panels rated at 500 kW DC) was generated using NREL's PVWatts Calculator, described in Section 3.2. The monthly PV energy estimate was then used to generate an estimated net load by subtracting the monthly PV production from the monthly billed energy consumption for each month. A new average capacity factor was calculated using the estimated net load and the bill KVARh total, assuming the PV system was producing at unity power factor. Since the daily load profile of the 55" pump station is relatively flat, the same billed demand charge was assumed. These new values were then used to calculate the estimated power factor adjustment with the PV system in place as shown by the blue line in Figure 18. The power factor adjustment credit was reduced by about $200 per month with the PV system in place as compared to the actual billed power factor adjustment shown in red. If the inverters of the PV system were able to produce enough kVARs to correct the power factor to 100%, then the power factor adjustment credit would only be reduced by approximately $50 per month as shown by the purple line. Even though the power factor of 100% is higher than the billed power factor, the power factor adjustment credit is still reduced from the billed power factor adjustment due to the lower net energy usage with the PV system in place. An annual savings of $1,800 warrants the consideration of including power factor correction with the PV system.

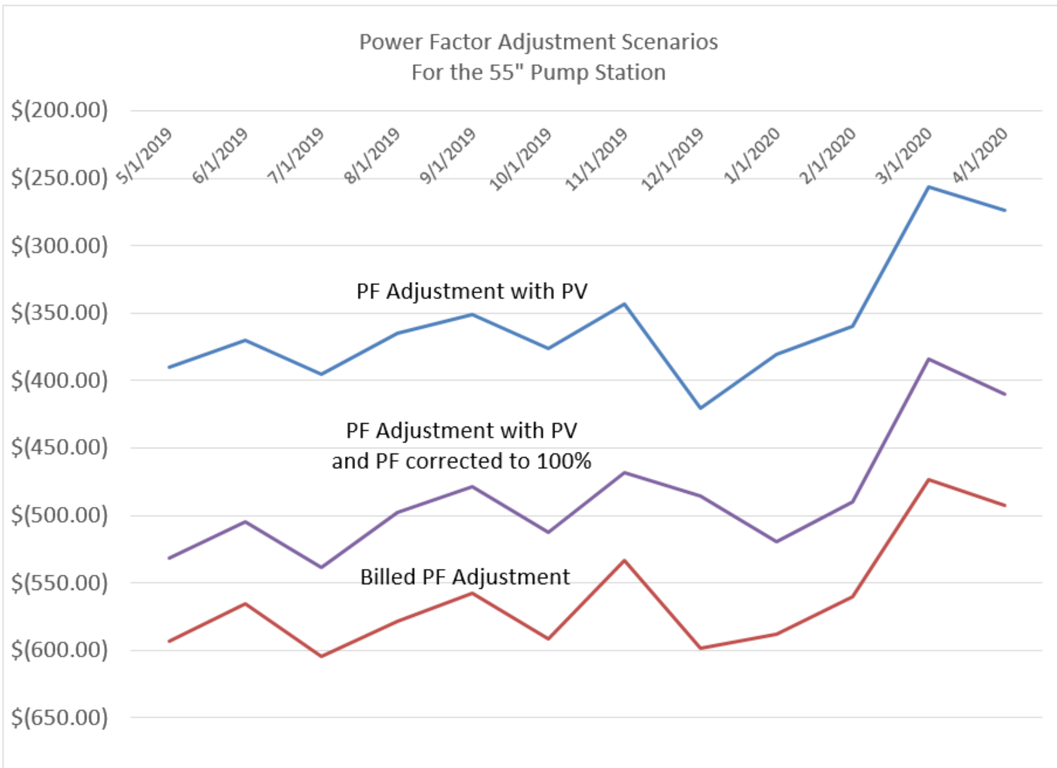

Figure 18. Power Factor Adjustment scenarios for the 55” pump station
Each line represents power factor adjustments of the actual, with PV, and with PV and a corrected power factor from May 2019 to April 2020.

4.7 Critical loads in the HOST Park

The seawater pump systems are the most critical loads at the HOST Park. The majority of the pumps are located in the 55” pump station and the Research Campus. These pumps consumed an average of 96.45% of the energy at the 55” pump station in 2019 and 88% of the energy at the Research Campus from September 2019 to December 2019. The SCADA data for the Research Campus was limited to the four months due to temporary meter malfunction. In the case of a power outage, the pump systems must be brought back online within two hours [1]. The primary seawater system at NELHA is the 55” deep seawater (DSW) pipeline and the 55” surface seawater (SSW) pipeline. Both of these pipelines come ashore to a common pumping station. The 55” DSW pipeline draws in cold seawater from a depth of 3,000 feet through 10,247 linear feet of submerged intake pipe. The 55” SSW pipeline draws in warmer seawater from a depth of 80 feet through 540 feet of the submerged intake pipe [1]. Table 7 lists the HOST Park’s critical loads at each site, as well as their monthly and yearly energy consumption.

Table 7. NELHA’s major critical loads at the HOST Park.
The data in the last two columns are sourced from HOST Park SCADA system.

Load	Station	Pump capacity each/total (Hp)	Average energy consumption /year (kWh) 2019	Average energy consumption /month (kWh) 2019
Surface seawater pumps (SSW #1 - 4)	Research Campus	77 / 308	426,123	35,510
Deep seawater pumps (DSW #11 - 13)	Research Campus	77 / 231	479,049	39,920
Deep seawater pumps (DSW #22 - 24)	Research Campus	35 / 105	142,510	11,876
Deep seawater pumps (DSW #21 & 25)	Research Campus	35 / 70	Not in use	Not in use
Surface seawater pumps (SSW #1 - 2)	55” pump station	200 / 400	1,012,560	84,380
Surface seawater pumps (SSW #3)	55” pump station	100 / 100	0	0
Deep seawater pumps (DSW #1 - 3)	55” pump station	200 / 600	1,506,953	125,579
Priming pump (#1 - 2)	55” pump station	3 / 6	0	0
ISSW pump (#1 - 2)	55” pump station	60 / 120	41,550	3,463
Pump #1 & #3	Booster pump station	100 / 200	119,727	9,977
Pump #2	Booster pump station	40 / 40	0	0

4.8 Power outage history

Table 8 lists the utility power outage events at the HOST Park from 2014 to 2019 that were identified from the HELCO meter data. Here, a utility power outage is identified as a period when HELCO did not deliver any power for at least a 15-minute metered interval to all of the load sections of the HOST Park. In a utility outage event, all of the HOST Park meters should not record any consumption. Two outage events colored with green and orange occurred in all of the meters suggesting that these are utility outage events.[5] The start time of the outage is the time of the first zero 15-minute consumption measurement and the end time is the time of the first non-zero measurement at the end of the outage. The outage colored in green lasted for approximately 45 minutes, and the outage colored in orange lasted for approximately one hour.

[5] HELCO meter data for the Farm Compound is only available starting from January, 2016.

HELCO measures the reliability of its system using several annual indices that are available on the Hawaiian Electric website.[6] These include the Customer Average Interruption Duration Index (CAIDI) and the System Average Interruption Frequency Index (SAIFI). CAIDI indicates the average time required to restore service for each year. SAIFI is the average number of interruptions that a customer would experience for each year. From 2015 to 2019, HELCO had a normalized CAIDI that ranged from 66.17 to 90.87 minutes and a normalized SAIFI that ranged from 1.784 to 4.127 outages. The normalized indices exclude major event days such as outages caused by large storms. Since the HOST Park is fed from underground circuits in an accessible area, the normalized indices would be an appropriate comparison.

The reliability indices above indicate that the reliability of the HOST Park is better than for the average HELCO customer. Both outages at the HOST Park in the last five years are shorter than HELCO's lowest CAIDI during that period and the HOST Park had a maximum of one interruption per year during that period which is less than HELCO's lowest SAIFI during that period. Historical grid outage data helps to quantify the typical duration that a microgrid will need to support its loads, and the frequency of the outages helps to quantify its value.

Table 8. HOST Park power outage events from 2014 to 2019
Each data point indicates zero energy consumption from the utility during the prior 15-minute period. The events were identified from HELCO 15-minute metered data.

Events	From HELCO meters (zero energy consumption)				
	Booster station	55" station	Kau pump	Farm Compound	Research Campus
1	8/8/14 06:45 - 07:30 (45 min)	8/8/14 07:00 - 07:45 (45 min)	8/8/14 06:45 - 07:30 (45 min)	11/2/16 22:45 - 11/3/16 05:15 (6 hours 30 min)	8/8/14 06:45 - 07:30 (45 min)
2	2/23/17 13:15 - 14:15 (1 hour)	2/23/17 13:30 - 14:30 (1 hour)	3/16/16 15:00 - 15:30 (30 min)	2/23/17 13:30 - 14:30 (1 hour)	2/23/17 13:30 - 14:30 (1 hour)
3		8/14/19 08:30 - 09:15 (45 min)	5/25/16 13:45 - 14:00 (15 min)		
4			11/2/16 22:45 - 11/3/16 05:30 (6 hours 45 min)		
5			12/16/16 06:00 - 06:30 (30 min)		
6			2/23/17 13:15 - 14:30 (1 hour 15 min)		

[6] The Hawaiian Electric website link: https://www.hawaiianelectric.com/about-us/key-performance-metrics/service-reliability.

4.9 Power outage protocol

Various load sections at the HOST Park have power outage protocols in place. Although the backup generators in each section take over the loads automatically during a grid power outage, the Research Campus follows a modified protocol to address the operation of the PV systems that are in that section. When a power outage occurs in the Research Campus, the inverter protection shuts down all the PV systems automatically, and the automatic transfer switches (ATS) disengage the loads from the grid. The backup generator powers up automatically, and the ATS shifts the loads to the generator. Once power is restored to the Research Campus grid by the backup generator, the pumps go through an auto-start sequence. The PV systems remain off while the backup generator supplies power to the Research Campus loads. When the utility power is restored, the ATS automatically transfers the power back to HELCO and begins the automatic shutdown procedures to cool down and turn off the generator. Once utility power is restored, the ground-mounted 35 kW PV is restarted manually by NELHA staff. The rooftop PV systems are restarted manually by the systems' owner.

5 Summary and next steps

The data and information contained in this Task 1 report indicate that the existing power system at the NELHA HOST Park has sufficient capacity and better-than-average reliability to meet the stated operational needs of the NELHA owned and/or managed loads. NELHA has adequate diesel backup generation capacity and fuel to power its critical pumping loads and the entire Research Campus in the event that its electric service supply from HELCO is interrupted. The longest localized outage in the last six years was a 6.5-hour outage at the Farm Compound and Kau Pump station in 2016 that did not impact the other NELHA meters. There are no critical loads at the Farm Compound and the diesel backup generation at the other NELHA load sections have more than enough fuel capacity to cover a 6-hour outage; the shortest backup generation run-time at full load was 16 hours at the Kau Pump Station and the longest duration was 51 hours at the Research Campus.

Nonetheless, the analyses carried out in connection with this report have revealed a number of opportunities for potential bill reduction and risk mitigation measures that could be implemented at the NELHA HOST Park. With respect to cost reductions, several instances of unusually high peak demand were identified for both the 55" pump station and the Research Campus load sections. The effective management of these types of events in the future presents opportunities for demand charge reductions and power factor improvements that could significantly reduce NELHA's electric bills. In addition, enabling the PV systems at the Research Campus to operate when the emergency generator is serving the loads could increase efficiency and extend the fuel supply.

Another consideration with regard to reliability and resiliency is that a backup generator failure during a power outage could disrupt seawater flow for more than two hours. In addition, given that NELHA owns the transformers serving the Research Campus and Farm Compound and bears the cost and responsibility of replacement (and therefore the risk of extended service disruption in the event of failure) it may be advisable for NELHA to revisit the ownership of these transformers and develop a plan to deal with a potential failure of these transformers.

Moving forward, HNEI is applying the information gathered in this Task 1 effort to identify both the technical and regulatory/policy opportunities and barriers in developing potential microgrid scenarios and solutions in the next steps. This includes evaluating potential energy resources (distributed generation, energy storage) and their controls to identify the most promising solutions that may be applied in microgrid solutions at the HOST Park.

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Appendix A:

NELHA transformers' serving site and their GPS coordinates

Transformers' serving site	GPS coordinates	Transformers' serving site	GPS coordinates
WHEA	19.714476° -156.035797°	55" Pump Station	19.712689° -156.047889°
Sopogy	19.714329° -156.035491	Beach Park	19.716695° -156.049695°
Gateway	19.714801° -156.035333°	Forever Ocean	19.721409° -156.053183°
Kona Deep	19.714892° -156.041679°	Marine Mammal Center	19.721321° -156.054333°
Destiny	19.716438° -156.036819°	SIS New Campus	19.722785° -156.054179°
Koyo A	19.716889° -156.038067°	SIS Main Campus	19.723427° -156.054611°
Koyo B	19.716922° -156.038049°	SIS Lot 99	19.723194° -156.056013°
Koyo C	19.716961° -156.038044°	Kau Pump Station	19.722924° -156.056041°
Koyo D	19.717358° -156.037215°	Keahole Point Hatcheries Main Campus, Ocean Rider	19.723043° -156.055989°
Koyo E	19.717369° -156.037184°	Cyanotech, Royal Hawaiian, Keahole Point Hatcheries (King Ocean Farm)	19.725921° -156.056065°
Keahole Point Provisions	19.715614° -156.038941°	Cyanotech #2	19.725690° -156.055858°
Moana Tech A	19.715627° -156.042564°	Sea Salt of Hawaii	19.725947° -156.058089°
Moana Tech B	19.716783° -156.042396°	Kona Cold Lobster	19.727412° -156.058537°
KOWA	19.713730° -156.044887°	Research Campus	19.728532° -156.060058°
Booster Pump Station	19.714174° -156.047557°	Farm Compound	19.728729° -156.058645°

NELHA Microgrid Project Task 3.2

Technology Information Gathering and Selection

Executive Summary

HNEI's Grid***START*** team has worked with NELHA to analyze the feasibility and benefits of modifying the current energy system at the HOST Park to enable it to operate as a microgrid (or a number of microgrids), potentially utilizing the existing HECO-owned distribution system within the HOST Park to distribute NELHA-generated energy within the park. Among other things, this undertaking has included an evaluation of the potential on-site distributed generation, energy storage, power management, and control technologies.

Under the circumstances solar PV generation paired with battery energy storage systems appear by far to be the most viable sources of energy to power a microgrid (or microgrids) at the HOST Park. Depending on the ultimate configuration and operation of the HOST Park microgrid, advanced controls may also be required to manage the coordination between the HOST Park's multiple backup generators, PV arrays and battery systems, while operating in islanded mode. However, especially with the variety and uncertainty of the actual technologies, manufacturers and configurations that are currently being implemented and/or envisioned for NELHA, such controls would likely be highly complex and sophisticated, and require a level of additional engineering analysis and design that is beyond the scope of this planning-level study.

Toward that end, the Hawaii PUC has consistently expressed its support for testing advanced grid technologies and market concepts that can facilitate microgrid development in general, as well as a microgrid demonstration project at the HOST Park in particular. One of the key regulatory considerations at this time appears to be whether and how such an arrangement would comport with the Microgrid Services Tariff ("MGS Tariff") that is the subject of the PUC's ongoing Microgrid Investigation. Significantly, the PUC indicated in a recent order that it accepts the provisions of the MGS Tariff allowing wheeling in the context of microgrids, which was previously viewed as a significant regulatory hurdle for third-party microgrid development. Although the PUC's Microgrid Investigation remains ongoing and the MGS Tariff is subject to change, the regulatory pathway to a microgrid demonstration project at the HOST Park appears both flexible and promising.

I. Background

On August 29, 2019, the Hawaii Natural Energy Institute of the University of Hawaii ("HNEI") contracted to provide a *NELHA HOST Park Microgrid Analysis* of the Natural Energy Laboratory of Hawaii Authority's ("NELHA") Hawaii Ocean Science and Technology ("HOST") Park. Pursuant to that contract, HNEI's Grid***START*** team has worked with NELHA to analyze the feasibility and benefits of modifying the current energy system at the HOST Park to enable it to operate as a microgrid (or a number of microgrids), potentially utilizing the existing HECO-owned distribution system within the HOST Park to distribute NELHA-generated energy within the park.

On August 14, 2020, HNEI submitted to NELHA its Task 3.1 *Report on NELHA Power System Requirements Analysis*. This report covers Task 3.2 on *Technology Information Gathering and Selection*.

Part II of this document addresses Task 3.2a, which provides:

> CONTRACTOR shall evaluate potential on-site distributed generation, energy storage, power management, and control technologies to identify the most promising ones that could be applied in a microgrid and NELHA HOST Park. This evaluation will include an assessment of the potential for on-site OTEC and use of existing energy storage demonstration projects including hydrogen.

Part III of this document addresses Task 3.2b, which provides:

> Based on the assessment of the current HOST Park grid architecture and likely microgrid architectures, CONTRACTOR shall identify current Hawai'i regulations and policies likely to impact development of an integrated microgrid serving the HOST Park. To the extent possible, CONTRACTOR will identify changes to the regulatory framework, including those governing wheeling that would facilitate microgrid development at NELHA and its impact on electricity rates to their tenants.

II. Potential Microgrid Technologies at NELHA HOST Park

A. On-site Distributed Generation

Advancements in energy production technologies and their proliferation into the consumer market are helping our electric systems migrate from traditional energy production and distribution models to more contemporary ones. Distributed generation ("DG") resources generate power closer to the point of end consumption than centralized generation[1] which requires power to be transmitted through a network of high-voltage transmission lines.[2] DG provides increased resiliency to the grid from extreme weather events that can damage or destroy transmission lines.

Although there are various DG technologies in use and in development today, this report will focus on seven that have the potential to best serve power requirements for the NELHA HOST Park. Each section will include a brief overview of the technology, its level of infiltration in global, national and state power generation portfolios, and its readiness for commercialization. Of the technologies discussed below, because of its market availability, wide implementation,

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[1] See United States Environmental Protection Agency, *Distributed Generation of Electricity and its Environmental Impacts,* USEPA [Cited May 27, 2021]. Available at: https://www.epa.gov/energy/distributed-generation-electricity-and-its-environmental-impacts.

[2] See United States Environmental Protection Agency, *Centralized Generation of Electricity and its Environmental Impacts,* USEPA [Cited May 27, 2021]. Available at: https://www.epa.gov/energy/centralized-generation-electricity-and-its-impacts-environment.

well developed supply chains, and reduced procurement and maintenance costs, distributed generation through solar photovoltaic panels ("solar PV") appears to be the most promising choice for the HOST Park microgrid. Further, the HOST Park's geographic location, climatic conditions, high solar insolation, and low rainfall make solar PV an even more ideal candidate for the HOST Park's energy requirements.

Other DG technologies discussed in this report could theoretically be adopted at the HOST Park microgrid. However, those technologies are either in their infancy, not suited to the Keahole environment, only economically viable if implemented on a large scale, and/or subject to potential community opposition. Thus, solar PV appears to be by far the most viable alternative.

1. Solar Photovoltaics

Solar PV generation is a commercially and economically proven technology, and the best alternative for on-site generation to power a microgrid within the NELHA HOST Park. In recent years, technology improvements and declines in manufacturing costs have accelerated the deployment of solar PV. As discussed below, geographic and climate factors on the leeward side of Hawaii Island make solar PV an attractive source of power generation at the HOST Park.

A solar PV cell generates electricity by converting sunlight into electric current. Most PV cells consist of two types of semiconductor layers (n-type and p-type layers) made from silicon. The cells create a voltage potential when enough sunlight is absorbed by the semiconductor materials. A typical solar PV system includes weather-tight PV modules that consist of multiple PV cells, a charge controller, and an inverter.

Solar PV is globally one of the most widely deployed sources of renewable energy, and its integration into conventional grid systems continues to grow rapidly. In recent years, improvements in module efficiency, reductions in supply chain costs, increases in labor productivity,[3] and growing policy support have fueled the global proliferation of utility-scale, residential, and commercial PV capacity; this trend is expected to continue.[4] The U.S. Department of Energy (DOE) Solar Energy Technologies Office (SETO) has set a goal for the levelized cost of commercial-scale PV energy to be \$0.04 per kWh by 2030.[5] This goal appears attainable as the deployment of solar PV is expected to increase with strong growth in many of the world's leading markets.[6] In Hawaii, solar PV has not only been a cleaner choice but also an

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[3] The installation cost for solar PV has dropped more than 70% over the last decade, and the total installed capacity of solar PV in the U.S. has reached 97.7 GWdc in 2020. See SEIA. *U.S. Solar Market Insight*. 2021 [cited 2021 April 5]; Available at: https://www.seia.org/us-solar-market-insight#:~:text=Solar%20accounted%20for%2043%25%20of,second%20year%20in%20a%20row; see also SEIA. *Solar Industry Research Data*. [cited 2021 April 5]; Available at: https://www.seia.org/solar-industry-research-data.
[4] The global solar PV capacity has grown 15 times larger between 2010 (3.2 GW) and 2019 (603 GW). See IEA. *Renewables 2020 Data Explorer*. 2020; Available at: https://www.iea.org/articles/renewables-2020-data-explorer?mode=market&region=World&product=PV.
[5] The U.S. commercial-scale levelized cost of PV energy was \$0.39 per kWh in 2010 and \$0.09 per kWh in 2020. See U.S. Department of Energy Solar Energy Technologies Office. *Photovoltaics*. [cited 2021 April 20]; Available at: https://www.energy.gov/eere/solar/photovoltaics.
[6] See NREL, *Q2/Q3 2020 Solar Industry Update*. 2020.

economically competitive choice for energy self-generation due to high electric utility tariff rates driven by a historical overdependence on imported fossil fuels for power generation.[7] As solar PV prices continue to decline and governments provide substantial tax credits to the commercial and residential sectors, solar PV installations are rapidly increasing.[8]

The rise in solar PV installations has also spurred growth in battery energy storage systems ("BESS"). When connected to solar PV systems, BESSs mitigate the intermittency of solar resources, providing dispatchable energy and reliable capacity. Reductions in BESS costs[9] and supportive state and federal energy policies have further accelerated the installation of commercial- and residential-scale solar PV coupled with BESSs in Hawaii.[10] Following the deployment of the United States' first utility-scale PV-plus-storage system on Kauai in December 2018, additional utility-scale PV-plus-storage projects are being developed throughout Hawaii.[11]

Situated at Keahole Point on the leeward side of Hawaii Island, the HOST Park receives high solar insolation and low rainfall (15 inches per year),[12] and its potential to foster solar PV system research and applications has been well recognized.[13] In fact, the suitability of solar PV systems at NELHA has already been proven by the successful installation and ongoing development of solar PV systems at the HOST Park. Approximately 200 kW of solar PV is currently installed at the HOST Park's Research Campus, and another PV-plus-storage system is under development at the southern end of the HOST Park, as part of the ongoing ENCORED project.

A larger portion of the forecasted energy demand at the HOST Park can be met with additional solar PV systems coupled with BESSs, potentially reducing energy costs, increasing reliability and resiliency, and supporting the achievement of Hawaii's renewable energy goals. The scalable nature of solar PV makes this technology particularly attractive for the HOST Park, where there exists considerable rooftop space and open land upon which additional rooftop and/or ground-mounted PV panels can be installed.

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[7] See U.S. Energy Information Administration, *Today in Energy.* 2018; Available at: https://www.eia.gov/todayinenergy/detail.php?id=34932

[8] In 2019, 2.5% and 10.2% of the electricity production in Hawaii accounted from utility scale PV and small-scale PV, respectively. See Hawaii State Energy Office, *Hawaii Energy Facts & Figures*. 2020: Honolulu, HI. p. 43.

[9] Lithium-ion battery pack prices have fallen 89% in 11 years to $137 per kWh in 2020, and the average price is predicted to be $100 per kWh by 2023. See Renewable Energy World, *Annual survey finds battery prices dropped 13% in 2020*. 2020.

[10] See Bai, J., D. Shuai, and E. Tian, *Solar PV Battery Installations in Honolulu: 2020 Update* 2021, State of Hawaii Department of Business, Economic Development, and Tourism. p. 9.

[11] See Fernandes, M., *Hawaiian Electric outlines new solar projects, totaling 460 MW*. 2020, Pacific Business News.

[12] The annual solar irradiation of the HOST Park is approximately 211 W per m^2, which is high intensity. See Giambelluca, T.W., X. Shuai, M.L. Barnes, R.J. Alliss, R.J. Longman, T. Miura, Q. Chen, A.G. Frazier, R.G. Mudd, L. Cuo, and A.D. Businger, *Evapotranspiration of Hawai'i. Final report submitted to the U.S. Army Corps of Engineers—Honolulu District, and the Commission on Water Resource Management*. 2014, State of Hawaii.

[13] See Natural Energy Laboratory of Hawaii Authority, *1998-99 Annual Report*. 1999.

2. **Concentrated Solar Power**

Concentrated solar power/concentrating solar-thermal power ("CSP") systems focus sunlight onto receivers utilizing mirrors or lenses, and the collected solar thermal energy is used to generate electricity. The sunlight collecting technologies can take several different forms such as parabolic trough systems, disk/engine systems, and power tower systems. Some utility-scale CSP plants are integrated with molten salt or molten silicon thermal energy storage to generate electricity at night using the energy captured during the day, i.e., time shift.[14] Although CSP systems have been implemented in the HOST Park area, additional installations are not recommended, as this technology is neither scalable nor economically feasible for a microgrid application there.[15]

Although CSP installed capacity is growing globally,[16] solar PV systems are outpacing CSP in terms of their cost points and ease of adoption, especially at commercial and residential scales.[17] To efficiently and cost-effectively operate a CSP plant without accurate sun tracking and weather forecasting systems, a contiguous area of land large enough to construct a plant with a generation capacity of 100 MW or higher is required.[18] An on-site CSP plant with the above specified capacity would be highly excessive for serving the HOST Park's relatively small loads. Moreover, the technology for smaller-scale CSP systems suitable for serving to HOST Park loads is not yet mature or commercially proven.[19]

3. **Ocean Energy Resources**

A variety of research and development ("R&D") and demonstration projects to harvest ocean energy for electricity production are actively taking place in Hawaii. However, ocean energy resources in general are not yet ready for commercial use. In its May 2019 report titled *Innovation Gaps,* IEA suggests that advancements in power technologies using ocean energy resources can be accelerated through concentrated research on essential components and sub-

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[14] See IEA, *How CSP's Thermal Energy Storage Works*. 2017; see also Deign, J., *CSP storage: is there value in non-thermal options?*, R. Events, Editor. 2014.

[15] Coining the term "MicroCSP," a venture capital-funded micro-scaled CSP firm, Sopogy, Inc. (Sopogy) developed the MicroCSP technology. However, the amount of electricity generated at the MicroCSP facility (460 kW) as well as the installed capacities of other small-scale CSP projects demonstrated in other parts of the world (100 to 300 kW) would not be sufficient to serve as an on-site generation resource for the microgrid at the HOST Park. See NREL, *Concentrating Solar Power Projects*. 2017; see also Rawlins, J. and M. Ashcroft, *Small-scale Concentrated Solar Power A review of current activity and potential to accelerate deployment*. 2013, Carbon Trust. p. 50.

[16] About 600 and 300 MW of CSP capacity were added globally in 2019 and 2020, respectively, mainly in Israel, China, South Africa, and Chile. See Bahar, H., *Concentrating Solar Power (CSP)*, IEA, Editor. 2020, IEA; see also IEA, *Renewables 2020*. 2020, IEA: Paris, France.

[17] Some CSP plant projects in China and Australia were abandoned due to financing challenges and the generation costs for CSP plants being three times higher than those for utility-scale PV plants. See IEA, *Renewables 2020*. 2020, IEA: Paris, France; see also IEA, *Renewable energy market update*. 2020, IEA: Paris, France.

[18] Zhao, Y., et al., *Photothermal effect of nanomaterials for efficient energy applications*, in *Novel Nanomaterials for Biomedical, Environmental and Energy Applications*. 2019, Elsevier. p. 415-434; see also Solar Energy Industries Association. *Concentrating Solar Power*. 2021 [cited 2021 February 15]; Available at: https://www.seia.org/initiatives/concentrating-solar-power.

[19] See Hawaii Reporter, *Sopogy's Demise is a Huge Victory for Honest Engineering and the Taxpayer*. 2014.

systems with an aim to reduce cost. IEA also recommends further research to diversify sources of ocean energy power as most of the technologies available now are either wave or tidal energy.[20]

a. **Ocean Thermal Energy Conversion**

Ocean thermal energy conversion ("OTEC") is a technology that converts ocean thermal energy to electricity by utilizing the temperature differences between the deep cold and relatively warmer surface ocean waters. OTEC is considered to be a potential base-load power supply because the deep ocean water temperature and the surface water temperature of the lower latitude areas (i.e., in the tropics) are relatively stable throughout the day and the seasonal ocean water temperature fluctuations can be easily predicted.[21] However, this technology is still in the R&D phase and its economic potential is unknown, as there is no commercial-scale plant currently in operation.[22]

Presently, there are only two continuously operational OTEC facilities globally.[23] One of those facilities is located in the HOST Park, and has a generation capacity of 105 kW, which is not sufficient to meet the facility's power requirements. Due to certain technological uncertainties, such as reliability in power generation, unproven cost-effectiveness, and lack of scalability, the OTEC facility operating at the HOST Park is not recommended to be used as an on-site generation resource for a NELHA microgrid.

b. **Wave Power**

Wave power systems capture the energy of ocean waves and convert it to electricity. They are also known as wave energy technologies or wave energy converters ("WEC"), and can be deployed at offshore, nearshore, or on-shore locations. WECs can be categorized according to three general system types: (1) oscillating water column system; (2) movable object system; and (3) overtopping system, each of which are in various stages of R&D.[24]

Several commercial wave power projects have been implemented globally.[25] However, the in-service periods of these projects were relatively short (from less than three months up to

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[20] See IEA, *Innovation Gaps*. 2019, IEA: Paris, France.
[21] See NEDO, *NEDO Renewable Energy White Paper (in Japanese)*. 2014, NEDO: Tokyo, Japan.
[22] See Langer, J., J. Quist, and K. Blok, *Recent progress in the economics of ocean thermal energy conversion: Critical review and research agenda.* 2020. 130: 109960; see also IEA, *Innovation Gaps*. 2019, IEA: Paris, France.
[23] See Makai Ocean Engineering. *Makai Connects World's Largest Ocean Thermal Plant to U.S. Grid*. 2015 [cited 2021 February 17]; Available at: https://www.makai.com/makai-news/2015_08_29_makai_connects_otec/; see also Power Academy. *Okinawa OTEC Facility Visitation Report (in Japanese)*. 2020 [cited 2021 February 17]; Available at: https://www.power-academy.jp/electronics/report/rep02800.html#:~:text=%E3%81%9D%E3%81%AE%E6%97%A5%E6%9C%AC%E3%81%A7%E3%81%AE%E5%94%AF%E4%B8%80,%E9%9B%BB%E5%8A%9B%E3%81%AB%E7%9B%B8%E5%BD%93%E3%81%97%E3%81%BE%E3%81%99%E3%80%82.
[24] See NEDO, *NEDO Renewable Energy White Paper (in Japanese)*. 2014, NEDO: Tokyo, Japan; see also Tethys. *Wave - Capturing energy from waves*. 2021 [cited 2021 March 4]; Available at: https://tethys.pnnl.gov/technology/wave.
[25] For example, the world's first grid-connected 500 kW shoreline wave power plant was commissioned in Scotland in 2000 and decommissioned in 2012. The 2.25 MW Aguçadoura Wave Farm in Portugal decommissioned after

two years). In the U.S., a few attempts to build commercial wave power plants have been made, but the projects were terminated due to technical, operational, and financing challenges.[26]

In Hawaii, several wave power R&D and demonstration projects have been piloted at the Wave Energy Test Site,[27] off the island of Oahu. Although the test site supports the nascent commercial wave energy sector by testing grid-connected WECs, the projects are generally research-focused, and no commercial level wave power project has yet been undertaken in Hawaii. Wave power systems are not currently a viable generation alternative for NELHA's microgrid, as the technology is not yet commercially proven or shown to be economically feasible. In addition, Keahole point is shielded by other Hawaiian Islands from the large northwest swells that arrive in Hawaii during the winter, which limits available wave resources.

c. Tidal Power

Tidal power technologies convert the kinetic energy of ocean tides into electric energy. Tidal power technology can be classified into two general systems: (1) tidal turbines (including tidal stream generator and tidal stream energy conversion); and (2) tidal impoundment (including tidal barrages and tidal lagoons). To economically produce electricity, the tidal power technologies require at least ten feet of tidal fluctuation.[28] In contrast, the tides in the Hawaiian Islands typically vary less than 3.5 feet due to the islands' geographical location (e.g., their proximity to amphidromic points) and the local topography of land and sea.[29] Consequently, ocean current and tidal power are not considered to be viable generation resources in Hawaii at this time.[30]

4. Wind Power

Wind power technology converts mechanical energy into electricity by utilizing the aerodynamic force captured by wind turbines. It is one of the most widely used types of renewable energy in the world today,[31] and the addition of wind power capacity is prominent in

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three months of commissioning due to technical failures and the financial collapse of a parent company. See The Queen's University of Belfast, *Islay Limpet Wave Power Plant Report*. 2002, Queens University. p. 62; BBC News Services, *Scotland's first wave firm, Wavegen, in trouble*. 2013; see also Tethys, *Companhia da Energia Oceânica SA (CEO) - Aguçadoura*. 2014.

[26] See Schwartz, D., *Wave Energy Developer Pulls Plug On Oregon Project*, in *Science Environment*. 2014, Oregon Public Broadcasting News: Portland, OR; see also Montaron, T. *Reedsport OPT Wave Park Plans Terminated*. 2014; Available at: https://tethys.pnnl.gov/stories/reedsport-opt-wave-park-plans-terminated.

[27] See Hawaii Natural Energy Institute, *Research Support to the U.S. Navy Wave Energy Test Site*. 2020: Honolulu, HI.

[28] See EIA. *Hydropower explained Tidal Power*. 2020 [cited 2021 April 24]; Available at: https://www.eia.gov/energyexplained/hydropower/tidal-power.php.

[29] See STAB. *Why Are Tides So Tiny In Hawaii And Enormous In Europe?* 2020 [cited 2021 April 24]; Available at: https://stabmag.com/news/why-are-tides-so-tiny-in-hawaii-and-enormous-in-europe/.

[30] See Hawaii State Energy Office, *Hawaii Energy Facts & Figures*. 2020: Honolulu, HI. p. 43.

[31] According to IEA, the global onshore wind capacity in 2019 (595 GW) was 35 times more than in the year 2000. Global offshore wind capacity also grew dramatically in the last decade from 3.2 GW in 2010 to 28.2 GW in 2019. See IEA. *Renewables 2020 Data Explorer*. 2020; Available at: https://www.iea.org/articles/renewables-2020-data-explorer?mode=market&region=World&product=Offshore+wind.

the U.S.[32] As more wind power technology is adopted commercially, various sizes and types of wind turbines are becoming available. In addition, multiple wind power R&D projects are being carried out in search of improvements in efficiency of small-scale wind power generation[33] and exploiting strong and consistent offshore winds.[34]

Although a substantial amount of electricity in Hawaii is generated from wind power plants[35] and new wind power technologies are being actively researched, the installation of wind power as an on-site generation resource at the HOST Park is not recommended. One of the major hurdles in constructing economically viable wind turbines at the HOST Park is its proximity to Kona International Airport. Large and tall wind turbines pose substantial safety issues for air traffic and face considerable community opposition due their visual impact and environmental concerns regarding endangered seabird deaths. At the same time, smaller and shorter wind turbines such as vertical-axis turbines are still in the R&D phase and not commercially proven.[36] Furthermore, the wind power density available at the HOST Park is significantly lower compared to other areas on Hawaii Island – for example in Hawi where Hawi Wind Farm is located.[37] Therefore, wind turbines do not appear to be a suitable generation resource at the HOST Park.

5. Geothermal Power

Geothermal power technology generally utilizes a geothermal reservoir, a source of underground water heated by thermal energy produced within the Earth's core. Once a suitably-sized geothermal reservoir is developed, geothermal power can serve as a base-load power supply since electricity can be generated continuously around the clock. In general, geothermal power technologies can be categorized into three systems: (1) flash steam systems; (2) binary cycle systems; and (3) engineered or enhanced geothermal systems. Unlike the older flash steam and binary cycle systems, engineered or enhanced geothermal systems enable energy extraction

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[32] The annual capacity in 2019 and cumulative capacity of land-based and offshore wind in the U.S. were 9,137 MW and 105 GW, respectively, both being the second largest amount in the world next to China. See Wiser, R., et al., *Wind Energy Technology Data Update: 2020 Edition*. 2020, Lawrence Berkeley National Laboratory. p. 87.

[33] For example, the Golden Gate National Parks Conservancy conducted a four-year research project in 2012 to study the efficiency of vertical-axis turbines that were developed to utilize winds in an urban area. See Golden Gate National Parks Conservancy, *TASK 4 Alternative Energy Systems 4.5 Energy Test Platforms: Crissy Field Center Wind Power Study: Final Report*. 2015; see also Banerjee, V. *Crissy Field Center Wind Turbines On The Cutting Edge Of Energy*. 2017; Available at: https://www.parksconservancy.org/park-e-ventures-article/crissy-field-center-wind-turbines-cutting-edge-energy.

[34] In March 2021, the U.S. Secretary of Energy announced the new offshore wind turbine deployment target to be 30 GW by 2030. See U.S. Department of Energy. *Energy Secretary Granholm Announces Ambitious New 30GW Offshore Wind Deployment Target by 2030*. 2021 [cited 2021 April 16]; Available at: https://www.energy.gov/articles/energy-secretary-granholm-announces-ambitious-new-30gw-offshore-wind-deployment-target.

[35] Wind power comprised 4.9% of Hawaii's electricity production in 2019. See Hawaii State Energy Office, *Hawaii Energy Facts & Figures*, H.S.E. Office, Editor. 2020: Honolulu, HI. p. 43.

[36] See Banerjee, V. *Crissy Field Center Wind Turbines On The Cutting Edge Of Energy*. 2017; Available at: https://www.parksconservancy.org/park-e-ventures-article/crissy-field-center-wind-turbines-cutting-edge-energy

[37] See Hawaii State Energy Office, *Renewable EnerGIS Map*. 2018.

from lower temperature reservoirs (180 to 350°C) or underground hot rock; however, this technology is still in its R&D and demonstration phases and is not commercially available.[38]

Regardless of the maturity of geothermal power technologies, the development of geothermal resources is traditionally considered riskier than other renewable resources due to high exploration and initial investment costs, as well as a high chance of failure.[39] The relative lack of scalability for geothermal generation would present additional challenges for a microgrid at the HOST Park. For instance, the only geothermal power plant in Hawaii, Puna Geothermal Venture (PGV), has a full capacity of 38 MW,[40] which is far greater than the required energy needs of the HOST Park. Similar to wind turbines, the development of a geothermal power facility at the HOST Park would likely be subject to community opposition due to environmental concerns and cultural sensitivities.[41]

6. Bioenergy

Bioenergy is a form of renewable energy that is derived from renewable organic materials such as crop wastes, forest residues, purpose-grown grasses, woody energy crops, microalgae, urban wood waste and food waste. Biomass is typically defined as renewable organic materials other than fossil fuels. The energy stored in biomass can be released by combustion, bacterial decomposition, or conversion to a gas or liquid fuel. The liquid fuels derived from biomass are called biofuels, which include biodiesel as a subcategory. The biomass power technologies discussed in this report consist of mechanisms that generate electricity utilizing biomass.[42, 43]

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[38] See Breeze, P., *Chapter 12 - Geothermal Power*, in *Power Generation Technologies (Third Edition)*, P. Breeze, Editor. 2019, Newnes. p. 275-291; see also EIA. *Geothermal explained*. 2020; Available at: https://www.eia.gov/energyexplained/geothermal/.

[39] After initial surveys of geothermal sources that are performed typically by national institutions, a developer needs to conduct further surveys by usually drilling three test wells, which can cost $2 million per well to drill with an approximately 30% chance of failure, and perform prefeasibility studies, which can cost $1 million, also with a 30% chance of failure. See IRENA, I. Takatsune, and R. Carlos, *Geothermal Power: Technology Brief*. 2017, International Renewable Energy Agency: Abu Dhabi, UAE; see also Breeze, P., *Chapter 12 - Geothermal Power*, in *Power Generation Technologies (Third Edition)*, P. Breeze, Editor. 2019, Newnes. p. 275-291; see also Lund, J.W., *Geothermal energy*. 2018, Encyclopedia Britannica.

[40] See Tribune-Herald staff, *PGV aims to return to full power generation by end of year*. 2021, Hawaii Tribune-Herald.

[41] PGV and its predecessor companies have experienced disputes with local communities for the religious, cultural sensitivity, and environmental oppositions; drilling noise; air pollution; and a June 1991 blowout among other incidents. See Department of Land and Natural Resources. *Geothermal History*. Available at: https://www.higp.hawaii.edu/hggrc/projects/geothermal-digital-collection/geothermal-collections/geothermal-development-2/; see also Environment Hawai`i, *At Puna Geothermal Venture, Success Is Always Just Around the Corner*. 1992: Hilo, HI.

[42] See U.S. Department of Energy Office of Energy efficiency and Renewable Energy. *Bioenergy Basics*. Available at: https://www.energy.gov/eere/bioenergy/bioenergy-basics.

[43] The Hawaii State Energy Office includes biofuel, biogas, and biomass energy projects under the category of bioenergy. See Hawaii State Energy Office, *Hawaii Energy Facts & Figures*. 2020: Honolulu, HI. p. 43.

a. **Diesel/Biodiesel Generators**

Biodiesel refers to fatty acid methyl esters and can be made from various components such as used cooking oil, vegetable oil and animal fats, through a chemical reaction known as transesterification. In the U.S. and Canada, the biodiesel standard, ASTM D 6751, defined by the American Society for Testing and Materials ("ASTM") is widely used,[44] and Pacific Biodiesel, which is the only commercial biodiesel producer in Hawaii, provides ASTM-certified fuel.[45]

Although ASTM-certified biodiesel is locally available, biodiesel would not be a cost-effective choice for the on-site generation for the HOST Park microgrid due to high biodiesel prices and various other operational costs. For the HOST Park, these costs would include transportation, storage and management of biodiesel; installation of additional diesel generators; compatibility tests with biodiesel for the existing four backup diesel generators; and negotiation of warranties with diesel engine original equipment manufacturers.[46]

b. **Biomass Power**

Biomass can be directly combusted for steam power generation or gasified to create biogas. Using biogas, electricity can be generated through a gas engine, gas turbine, biogas fuel cell, or direct combustion (boiler and steam turbine). The energy efficiency of biomass power plants can be greatly increased by combining the use of mechanical and thermal energy (i.e., a combined heat and power (CHP) or cogeneration system).[47]

Like biodiesel, the lack of on-site biomass and associated costs (costs related to securing, procuring, delivering, storing, and managing biomass on-site) would make biomass power a less attractive choice for on-site generation for the HOST Park. Many DG-scale and commercial-scale biomass power facilities that use woody biomass are installed at places where a significant amount of waste is available – such as a lumber and paper mill – to achieve cost-effectiveness.[48] For example, Hawaii's two utility-scale biomass power plants, the Green Energy Biomass-to-

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[44] IEA Advanced Motor Fuels. *Fatty Acid Esters (biodiesel)*. Available at: https://www.iea-amf.org/content/fuel_information/fatty_acid_esters.
[45] See Hawaii State Energy Office, *Hawaii Energy Facts & Figures*. 2020: Honolulu, HI. p. 43.
[46] Generating electricity with pure biodiesel, or B100, which reduces 74% of carbon dioxide life-cycle emissions, costs more than twice compared to the use of conventional diesel. On the other hand, the average price of B20 (blend of 20% biodiesel and 80% conventional diesel) has been lower than the average price of conventional diesel since October 2016; however, B20 reduces only 15% of the carbon dioxide life-cycle emissions compared to conventional diesel. In Hawaii, the December 2020 cost of biodiesel per kWh electricity generation was $0.27, whereas that of conventional diesel was $0.11 per kWh. See State of Hawaii. *Biodiesel FAQs*. Available at: https://climate.hawaii.gov/biodiesel/; see also State of Hawaii Department of Business, Economic Development & Tourism, *Economic Data Warehouse*. 2020.
[47] See NEDO, *NEDO Renewable Energy White Paper (in Japanese)*. 2014, NEDO: Tokyo, Japan; see also EIA. *Biomass explained*. 2020; Available at: https://www.eia.gov/energyexplained/biomass/.
[48] See U.S. Department of Energy Federal Energy Management Program. *Biomass For Electricity Generation* 2016; Available at: https://www.wbdg.org/resources/biomass-electricity-generation#:~:text=Most%20biopower%20plants%20use%20direct,processes%20or%20to%20heat%20buildings.

Energy facility[49] on Kauai and the Honolulu Program of Waste Energy Recovery (H-Power),[50] both utilize biomass that is readily available locally or on-site. In contrast, adequate sources of biomass are not readily available at the HOST Park. In addition, proposed biomass facilities in Hawaii (such as the Honua Ola facility on Hawaii Island) have faced regulatory challenges related to community acceptance and cost-effectiveness, especially with the sharp decline in the prices and costs for other types of renewable generation.[51]

7. Small Hydropower

Hydropower uses falling or fast-running water to drive a turbine and an electrical generator. The sizing of hydropower generation is generally determined by head (vertical change in elevation) and water flow conditions. The U.S. DOE defines the sizes of hydropower plants as follows:

- very large hydropower (more than 500 MW);
- large hydropower (between 100 MW and 500 MW);
- medium hydropower (between 10 MW and 100 MW);
- small hydropower (between 0.1 MW and 10 MW); and
- micro hydropower (less than or equal to 0.1 MW).[52]

Small hydropower is a renewable energy technology that is developed on a scale suitable to contribute to DG.[53] Unlike conventional hydropower facilities with very large dams or reservoirs, many small and micro hydropower projects utilize run-of-river facility channels that capture energy from low-head stream flows or irrigation infrastructure[54] or in-pipe hydropower systems that harness excess head pressure in urban and domestic water pipelines.[55] Both run-of-

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[49] Wood biomass from its own local wood plantations is used. See Hawaii State Energy Office, *Hawaii Energy Facts & Figures*. 2020: Honolulu, HI. p. 43.
[50] Post-recycled municipal solid waste and sewage sludge are processed and burnt to generate electricity. See State of Hawaii Public Utilities Commission, *Annual Report for Fiscal Year 2020*. 2020. p. 78.
[51] The construction of a proposed 21.5 MW wood-fired combustion power plant by Honua Ola Bioenergy (Honua Ola), formerly known as Hu Honua Bioenergy LLC, on Hawaii Island, was delayed due to legal disputes, opposition from environmental organizations and local communities, and flooding. Later, a request for a competitive bidding waiver for Honua Ola was denied by the Hawaii Public Utilities Commission (PUC) because the electricity pricing of Honua Ola ($0.221 per kWh) was more than double of two other approved PV and BESS projects ($0.08 and $0.09 per kWh) on Hawaii Island. See Armstrong, J., *Big Island: Proposed Biofuel Plant Faces $100M Deadline*. 2018; see also Big Island Video News, *Hu Honua Bioenergy Project Fails To Get Needed Approvals*. 2020; see also State of Hawaii Public Utilities Commission, *Denying Hawaii Electric Light Company, Inc.'s Request for a Waiver and Dismissing Letter Request for Approval of Amended and Restated Power Purchase Agreement*. 2020. p. 59.
[52] See Johnson, M., R. Uria-Martinez, and P. O'Connor, *2014 Hydropower Market Report Data*. 2015, Oak Ridge National Lab, Oak Ridge, TN.
[53] See U.S. Department of Energy Office of Energy Saver. *Planning a Microhydropower System*. [cited 2021 April 17]; Available at: https://www.energy.gov/energysaver/planning-microhydropower-system.
[54] See U.S. Department of Energy Water Power Technologies Office. *Types of Hydropower Plants*. [cited 2021 April 17]; Available at: https://www.energy.gov/eere/water/types-hydropower-plants.
[55] See Ramos, H.M., et al., *Inline Pumped Storage Hydropower towards Smart and Flexible Energy Recovery in Water Networks.* Water, 2020. 12(8): p. 2224.

river facilities[56] and in-pipe hydropower systems[57] have been implemented and are generating electricity on Hawaii Island.

Due to the HOST Park's geographical characteristics, small hydropower does not appear to be a viable alternative for on-site generation. There is no stream or flume at the HOST Park, Likewise, because the grade of the HOST Park property is relatively small and there are no gravity-fed water networks that require constant pressure reduction, serving the energy needs of the HOST Park with in-pipe hydropower systems does not appear to be viable.

B. Energy Storage

As noted above, energy storage plays a substantial role in integrating variable renewable power sources with existing power grid systems and helps to create a more flexible and reliable grid. Some of the beneficial applications of energy storage include balancing electricity demand and supply through peak-shaving and/or load-leveling, supporting intermittent renewable energy supply and reducing electricity bills. Energy storage is also important to microgrids, particularly when they are disconnected from the main power grid. Therefore, energy storage is a key component of an overall microgrid system.

With the increase in installed renewable energy and the declining costs of energy storage technologies, there are substantial benefits in combining renewable energy with energy storage. A major focus of recent technological innovation and commercialization has been on BESSs. Combined with solar PV, BESSs represent the most attractive on-site energy storage technology for a HOST Park microgrid. In addition to BESSs, this section also briefly overviews three additional energy storage technologies – hydrogen storage, pumped hydro storage and compressed air storage, and their applicability within the HOST Park.

1. Electrochemical Battery Energy Storage Systems

Similar to battery cells for electric vehicles and smartphones, electrochemical battery energy storage systems, or BESSs, store energy in a chemical form. Among the four main battery types (lead-acid, lithium-ion, sodium-sulfur, and flow batteries), lead-acid and lithium-ion are the most commonly used types of batteries in the world.[58] In particular, the market and demand for lithium-ion BESSs is growing rapidly because of its light weight, high roundtrip

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[56] The Wailuku River Hydroelectric Plant has the highest hydropower capacity (about 10 MW) in Hawaii and is located at the junction of the Wailuku River and the Kaloheahewa Stream approximately 2.5 miles outside of Hilo. The Waiau and Puueo Hydropower plants by Wailuku River near Hilo are not currently operating. See Hawaii State Energy Office, *Hawaii Energy Projects Directory*. 2021.

[57] Kahaluu Shaft Hydro is a 42 kW rated output in-line hydroelectric turbine system installed on the County of Hawaii Department of Water Supply's Kahaluu Shaft potable water system. Kaloko Tank No.2 Hydro is a 50 kW unit installed on the Kaloko Tank No.2 water system in Kailua-Kona. See Hawaii State Energy Office, *Hawaii Energy Projects Directory*. 2021.

[58] See Schiek, A., et al., *Global Overview of Energy Storage Performance Test Protocols*. 2021, NREL.

efficiency, high power density, large supply chain availability, and declining costs.[59] As a result, it is increasingly common for lithium-ion BESSs to be installed together with solar PV systems.

In Hawaii, most of the utility-scale BESSs are paired with onshore wind or solar PV systems to store excess wind or solar generation.[60] Out of 20 utility-scale renewable energy projects approved or awaiting to be approved by regulators, 3 projects are standalone BESS projects, and 17 projects are solar plus BESS projects.[61] Residential- and commercial-scale BESS projects are also significantly growing in number, particularly after HECO's Net Energy Metering (NEM) program was closed to new applicants in 2015.[62] The HOST Park site has been used to demonstrate several energy store systems, the most recent being a 250 kW/760 kWh BESS as part of an advanced microgrid project (the ongoing ENCORED project) announced in 2021.[63]

Unlike fossil fuel-based generation plants, energy produced from renewable sources, such as wind or solar, have a limited ability to adapt to shifting energy demands. Further, solar insolation is often sporadic – affected by occasional cloud cover – and thus does not guarantee a steady flow of power. BESS technologies, together with solar PV, not only help regulate fluctuations in solar energy production and provide a steady energy output, but they can also help absorb excess solar energy in electrochemical batteries. The excess can then be discharged during times of low solar insolation or at night. Working in conjunction with solar PV systems, BESSs can increase the resiliency of microgrids and reduce dependence on energy purchased from utilities. BESS technologies are commercially proven and cost-efficient to implement, especially with Hawaii's high electricity costs. BESSs are also scalable, have a small footprint, and widely used on a commercial scale in Hawaii. As a result, procuring, installing, and maintaining BESSs in the HOST Park would be a relatively low-risk and cost-efficient undertaking – rendering BESS technologies the most ideal candidate for energy storage at the HOST Park

2. Hydrogen Storage

Hydrogen storage can be utilized to store excess renewable energy for later use. The excess electric power is used to produce hydrogen and oxygen from water by means of electrolysis. The energy is stored as hydrogen gas for later use through a gas turbine, fuel cell, or

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[59] In 2020, over 1 GW of lithium-ion BESSs were deployed in the U.S., which was the highest number of installations in one year. See Colthorpe, A., *In 2020 the US went beyond a gigawatt of advanced energy storage installations for first time ever*. 2021.

[60] Both Maui and Hawaii Island have mandatory energy storage requirements for new solar projects. See EIA. *Most of Hawaii's electric battery systems are paired with wind or solar power plants*. 2020 [cited 2021 April 23]; Available at: https://www.eia.gov/todayinenergy/detail.php?id=43215.

[61] See Hawaii State Energy Office. *Hawaiian Electric Stage 1 and 2 Renewable Energy Projects*. 2021 [cited 2021 May 24]; Available at: https://energy.hawaii.gov/hawaiian-electric-phase2.

[62] The number of building permits in the Honolulu County related to residential PV plus battery installation increased from five in 2015 to 3,336 in 2020. See Bai, J., D. Shuai, and E. Tian, *Solar PV Battery Installations in Honolulu: 2020 Update* 2021, State of Hawaii Department of Business, Economic Development and Tourism. p. 9.

[63] See State of Hawaii Department of Business, Economic Development & Tourism. *Hawaii Announces Alliance with Republic of Korea to Develop and Build an Advanced Microgrid at the Natural Energy Laboratory in Kailua-Kona*. 2021 [cited 2021 April 23]; Available at: http://dbedt.hawaii.gov/blog/21-12/.

other type of generator. Across the globe, pilot projects to develop large-scale, long-duration hydrogen storage solutions using salt caverns are being undertaken in the UK, UAE, Australia, China, and the U.S. (e.g., Advanced Clean Energy Storage Project in Delta, Utah).[64] In addition, various hydrogen storage R&D efforts currently being undertaken for onboard light-duty vehicle, material-handling equipment, and portable power applications.

In 2019, HNEI installed a hydrogen station at the HOST Park to evaluate the technical and financial feasibility, equipment durability, and ability to support a fleet of three hydrogen fuel cell electric buses.[65] However, the produced hydrogen is not planned to be used as source of electricity generation and storage beyond the context of hydrogen buses. Furthermore, hydrogen storage presents a number of challenges, such as explosion hazard, high production costs, low round-trip efficiency (~30%), and high-density hydrogen storage for stationary applications.[66] Therefore, it is not an ideal choice for on-site energy storage for a microgrid at the HOST Park.

3. Pumped-Storage Hydropower

Pumped-storage hydropower ("PSH") is a type of hydroelectric energy storage that stores the potential energy of the water at a higher elevation. In the U.S., 92% of utility-scale energy storage capacity collectively comes from the PSH facilities,[67] most of which were built in the 1970s.[68] These traditional PSH facilities typically require upper and lower reservoirs, a large head, an underground powerhouse, and large capacity to overcome the fixed costs associated with custom engineering of complex underground structures with associated geological risk. As distributed renewable energy costs decline and focus on energy storage increases, interests in small- or micro-scale PHS systems with reduced cost and scale has grown in recent years. The National Renewable Energy Laboratory (NREL) and its partners are currently demonstrating the scalability (1 to 100 MW), geological flexibility (e.g., without an underground powerhouse and reservoirs), and economical feasibility of a small PSH system using a vertical well.[69]

Although additional R&D efforts are still underway to improve the already-matured PSH technologies, PSH systems do not offer any economic advantage over BESSs as on-site energy storage solutions for a HOST Park microgrid. As discussed above, the HOST Park's relatively

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[64] See Mandel, E. *Mitsubishi Power progresses with hydrogen storage solutions in the US*. 2021 [cited 2021 May 25]; Available at: https://www.h2bulletin.com/mitsubishi-power-progresses-with-hydrogen-storage-solutions-in-the-us/.
[65] See HNEI. *HNEI Hydrogen Production And Fueling Station at NELHA*. 2019 [cited 2021 May 25]; Available at: https://www.hnei.hawaii.edu/wp-content/uploads/NELHA-H2-Station-Overview.pdf.
[66] See U.S. Department of Energy Office of Energy efficiency and Renewable Energy. *Hydrogen Storage*. [cited 2021 May 25]; Available at: https://www.energy.gov/eere/fuelcells/hydrogen-storage.
[67] See EIA. *Utility-scale batteries and pumped storage return about 80% of the electricity they store*. 2021 [cited 2021 May 25]; Available at: https://www.eia.gov/todayinenergy/detail.php?id=46756.
[68] See EIA. *Most pumped storage electricity generators in the U.S. were built in the 1970s*. 2019 [cited 2021 May 25]; Available at: https://www.eia.gov/todayinenergy/detail.php?id=41833.
[69] See Obermeyer, H. *Cost Effective Small Scale Pumped Storage Configuration*. 2019 [cited 2021 May 26]; Available at: https://www.energy.gov/sites/prod/files/2019/12/f69/04_EE0008014_Obermeyer_Obermeyer%20Hydro_FINAL.pdf.

flat geographical characteristics and lack of adequate reservoirs on the property would render construction of a traditional PSH system extremely capital intensive and not cost effective.

4. Compressed Air Energy Storage

Compressed air energy storage ("CAES") uses excess energy to compress air and store it in pipes or underground caverns. The compressed air can then be run through a turbine to generate electricity at a later time. As the HOST Park lacks natural underground caverns suitable for storing compressed air, a CAES system at the HOST Park would likely require capital investments well in excess of the cost of a BESS. Although there are some existing CAES R&D projects that do not require underground caverns (e.g., CAES using underground porous and permeable rock structures[70] and ocean or underwater CAES[71]), such technologies are not yet commercially proven. In addition, CAES facilities typically have high power ratings and storage capacities far greater than the energy storage needs for a microgrid at the HOST Park. As a result, CAES does not appear to be a viable energy storage solution for a HOST Park microgrid at this time.

C. Control Techniques/Technologies

Microgrid control techniques and technologies have been widely studied to achieve safe and reliable operations while coordinating various kinds of DGs and multiple loads within a microgrid or multiple microgrids. Microgrids are controlled in various ways depending on the mode of operation (grid-connected or islanded mode) or the scale and complexity of the microgrid(s). While state-of-the-art control methods rely on information and communication technology ("ICT"), such sophistication in control methods may not be necessary for a relatively small and simple microgrid sufficient to meet NELHA's needs at the HOST Park. Nonetheless, a brief discussion of modes of operation and control methods for microgrids is provided below.

1. Mode of Operation

Microgrids typically function in one of two operational modes: (1) grid-connected mode; or (2) islanded mode. In grid-connected mode, the microgrid is connected to the main power grid, such as HECO's system. Since the voltage and frequency are maintained by the main power grid, the objective of the microgrid in grid-connected mode is to control active and reactive power (PQ control). PQ control aims to keep the energy sources' active power and reactive power constant at a given reference value within the permissible frequency range or voltage range. The voltage and frequency deviation limits are usually prescribed in a grid code; therefore, a key goal of a microgrid control in grid-connected mode ultimately is to meet the utility's rules and requirements.

In islanded mode, the microgrid is disconnected from the main power grid due to planned or unplanned events such as system faults. The objective of the microgrid control in islanded

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[70] See Pacific Northwest National Laboratory. *Compressed Air Energy Storage*. 2019; Available at: https://caes.pnnl.gov/.
[71] See Tweed, K., *Toronto Hydro Pilots World's First Offshore Compressed-Air Energy Storage Project*, in *Energy Storage*. 2015, A Wood Mackenzie Business.

mode is to control both voltage and frequency while supporting the energy demand within the microgrid boundary.[72] The system frequency and voltage magnitudes are designed to remain within acceptable limits regardless of the actual active and reactive power outputs of the energy sources within the microgrid.

2. Control Techniques and Methods

Microgrid control methods in islanded mode are generally classified into conventional and advanced control methods. Conventional control methods, which include droop control and master-slave control techniques, are capable of maintaining the voltage and frequency of the microgrid system.

Droop control is widely adopted both in microgrids and for conventional power plants because it does not require a communication channel. Similar to active power and frequency for conventional power plants, reactive power and terminal voltage have a linear relationship, and the voltage of a microgrid in islanded mode can be controlled by adjusting the reactive power output of on-site DGs.[73]

Unlike the droop control technique, the master-slave control technique requires communication channels with higher bandwidths. When a microgrid enters into islanded mode, a "master" unit (either on-site DG, energy storage system, or both) switches to a voltage and frequency control mode while other on-site DGs (i.e., the "slave" units) continue to operate in PQ control mode. When a microgrid is operating in grid-connected mode, the main power grid operates as the "master" unit, and a converter in the microgrid acts as the "slave" unit.[74]

More advanced control methods, such as centralized, decentralized, distributed, and hierarchical controls, provide supervisory control and intelligent and adaptive techniques in addition to voltage and frequency control;[75] however, such advanced control methods may be unnecessary for a relatively simple microgrid at the HOST Park, where the number of loads, DGs and BESSs are relatively small and situated near each other, and their level of interaction is relatively simple. In the absence of an actual identified need for advanced controls, it appears that implementing advanced controls at the HOST Park may add unnecessary complexity and cost to the installation, operation and maintenance of the system.[76]

Although the HOST Park rarely experiences power outages (six outage events occurred between 2014 and 2019 with durations ranging from 15 minutes to 7 hours), the operation of a HOST Park microgrid during an outage – particularly an extended outage – may give rise to a need for control methods that are more advanced than conventional control techniques. During

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[72] See Ekanayake, U.N. and U.S. Navaratne, *A Survey on Microgrid Control Techniques in Islanded Mode.* Journal of Electrical and Computer Engineering, 2020.
[73] See Gao, D., *Basic Concepts and Control Architecture of Microgrids.* Energy Storage for Sustainable Microgrid, 2015.
[74] See id.
[75] See Roslan, M., et al., *Microgrid control methods toward achieving sustainable energy management.* Applied Energy, 2019. 240: p. 583-607.
[76] Sun, J., *Microgrid Fundamentals and Control*. 2014, Rensselaer Center for Future Energy Sytems.

past outages when the HOST Park has been disconnected from the HECO system, NELHA has disconnected its on-site PV generation and served its loads by utilizing its backup diesel generators. In the future, if NELHA wishes to utilize its PV and BESS resources to provide supplemental power to its microgrid during outages, some combination of diesel generation and battery power will be necessary to manage the variations in voltage and frequency caused by its PV generation (which are ordinarily regulated by virtue of being connected to the larger HECO system).

A potential hurdle with such a mode of operation is that higher levels of on-site PV generation could push the HOST Park's diesel units below their minimum operating levels, to the point that they trip off; and without the diesel units providing voltage and frequency regulation to manage the PV resources, the only other source of regulation would be from its PV plus battery inverters. In this regard, advanced controls could be called upon to manage the coordination between the HOST Park's multiple backup generators, PV arrays and battery systems. However, especially with the variety and uncertainty of the actual technologies, manufacturers and configurations that are currently being implemented and/or envisioned for NELHA, such controls would likely be highly complex and sophisticated, and require a level of additional engineering analysis and design that is beyond the scope of this planning-level study.

III. Regulatory Considerations for a Microgrid Serving the NELHA Host Park

A. Summary

As it relates to a microgrid at the HOST Park, the Hawaii Public Utilities Commission ("PUC") has expressed its support for testing advanced grid technologies and market concepts that can facilitate microgrid development consistent with State energy policies, which specifically identify potential opportunities for a microgrid demonstration project at the HOST Park. One of the key regulatory considerations at this time appears to be whether and how such an arrangement would comport with the microgrid services tariff ("MGS Tariff") that is the subject of the PUC's ongoing microgrid investigation in Docket No. 2018-0163 ("Microgrid Investigation").

On May 27, 2021, the PUC issued a decision and order on Phase 1 of its Microgrid Investigation which, among other things, approved a MGS Tariff for the Hawaiian Electric Companies ("HECO"). Significantly, the PUC indicated in that order that it accepts the provisions of the MGS Tariff allowing wheeling, with no direct compensation. However, that docket remains open and the PUC has indicated that it intends to issue a procedural order to govern a forthcoming Phase 2 in which certain unresolved issues regarding the MGS Tariff will be addressed. In that the MGS Tariff is subject to change, there is no definitive regulatory guidance to date on whether a microgrid at the HOST Park would fit within the confines of the MGS Tariff, once finalized. In any event, the applicability of the MGS Tariff to a microgrid at the HOST Park will likely depend in part on the configuration of the microgrid itself.

Under the MGS Tariff, eligible microgrids generally fall into one of two categories, depending on whether they use utility infrastructure: (1) Customer Microgrids (which do not use any utility infrastructure); and (2) Hybrid Microgrids (which use utility infrastructure). Some of the key elements of a Customer Microgrid under the draft MGS Tariff are:

- A Customer Microgrid may intentionally enter into and out of Island Mode on a scheduled or unscheduled basis;
- The operator of a Customer Microgrid may allocate costs without markup for electric service received from the Company to other persons within the electrical boundaries of the microgrid.

Some of the key elements of a Hybrid Microgrid under the draft MGS Tariff are:

- A Hybrid Microgrid may only enter Island Mode during (1) emergency events, or (2) as otherwise permitted or directed by the Company;
- While operating in Island Mode, all energy delivered and sold within the microgrid is deemed to have been transacted with the Company pursuant to existing tariffs, and the operator is compensated for the energy it generates in the form of Energy Credit Rates as set forth in HECO's Customer Grid Supply Plus (CGS+) tariff;
- The total peak demand of a Hybrid Microgrid on Hawaii Island generally may not exceed 1 MW; and
- Hybrid Microgrids are subject to heightened administrative requirements, including submission and utility approval of a Hybrid Microgrid Application, disclosure checklists from the operator to other microgrid participants, and additional monitoring and reporting requirements.

NELHA currently has four existing metered accounts at the HOST Park that provide electric service to NELHA's: (1) 55-inch Pump Station; (2) Booster Pump Station; (3) Research Campus; and (4) Farm Compound. Certain portions of the distribution system that connects these loads currently use HECO-owned infrastructure. In addition, the total peak demand of these loads appears to be in excess of 1 MW. As a result, depending on its ultimate configuration, a microgrid at the HOST Park may or may not qualify as a "Customer Microgrid" or a "Hybrid Microgrid" under the draft MGS Tariff.

If neither the "Customer Microgrid" nor the "Hybrid Microgrid" constructs are capable of meeting NELHA's needs at the HOST Park, consideration may be given to proposing an "Alternative Hybrid Microgrid." In this regard, the MGS Tariff provides that the developer of a proposed Hybrid Microgrid may make a proposal for a microgrid not covered by the MGS Tariff, which would, if acceptable to HECO, be incorporated in a separate agreement with HECO that is subject to PUC approval.

A key benefit of pursuing an Alternative Hybrid Microgrid may be that it would enable an arrangement better-suited to NELHA's unique situation at the HOST Park. Unlike Hybrid Microgrids in other areas that would potentially utilize HECO's distribution assets while operating in both Grid Connected Mode and Island Mode, the HOST Park is situated "at the end of the line" within HECO's distribution system, and therefore the HOST Park microgrid would in effect only be using the HECO line for microgrid purposes during outages (i.e., during very rare instances while in Island Mode when the line is not being used for utility purposes). In that

NELHA's limited use of this line will not have any impact on customers outside of the HOST Park microgrid, the cross-subsidization concerns typically associated with the "wheeling" of electricity should not apply to this situation.

Another consideration in the design of a microgrid at the HOST Park is whether NELHA would serve as the microgrid operator for only NELHA-owned loads. Under such an arrangement, customers within the HOST Park other than NELHA would be disconnected from the microgrid upon entering into Island Mode. A potential advantage of this "operator-only" arrangement is that it could be relatively simple from an administrative standpoint. It is recognized, however, that NELHA may have tenants at the HOST Park who desire to participate in a NELHA-operated microgrid. Some of the considerations for enlisting third-party microgrid participants at the HOST Park include NELHA's working relationships with its tenants and familiarity with their electric loads, as well as public policy reasons to avoid disconnecting loads that are critical for serving the general public.

B. <u>Wheeling and Microgrid Legislation</u>

On April 30, 2004, the Hawaii Legislature adopted Senate Concurrent Resolution No. 180 ("S.C.R. No. 180") which, among other things, recognized the State's need to emphasize renewable energy programs and requested the PUC to explore ways to implement intra-governmental wheeling to facilitate government wheeling of electricity, and other regulatory measures to support the development of renewable energy systems by federal, state and county agencies. As defined in S.C.R. No. 180, wheeling is "the process of transmitting electric power from a seller's point of generation across a third-party-owned transmission and distribution system to the seller's retail customer."[77] In accordance with S.C.R. No. 180, on June 29, 2007, the PUC instituted a proceeding in Docket No. 2007-0176 to investigate the issues related to intra-governmental wheeling of electricity in Hawaii ("Intra-Governmental Wheeling Investigation").

Subsequently on July 10, 2018, Governor Ige signed Act 200 of 2018 *Relating to Resiliency* ("Act 200") into law. Among other things, Act 200 revised Hawaii's Public Utilities Law (Chapter 269 of the Hawaii Revised Statutes ("HRS")) to add new section, now codified as HRS § 269-46, which defines a MGS Tariff as a tariff approved by the PUC that:

> (1) Is designed to provide fair compensation for electricity, electric grid services, and other benefits provided to, or by, the electric utility, the person or entity operating the microgrid, and other ratepayers;
> (2) To the extent possible, standardizes and streamlines the related interconnection processes for microgrid projects; and
> (3) Does not apply to municipal utility cooperative.

Specifically, a microgrid project is defined by HRS § 269-46 to mean:

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[77] <u>See</u> Docket No. 2007-0176, Order No. 23530 (Haw. P.U.C., June 29, 2007) at 1-2.

> [A] group of interconnected loads and distributed energy resources within clearly defined electrical boundaries that acts as single controllable entity with respect to the utility's electrical grid and can connect to a public utility's electrical grid to operate in grid-connected mode and can disconnect from the grid to operate in island mode, and that: (1) Is subject to a microgrid services tariff; and (2) Generates or produces energy.[78]

C. <u>Microgrid Investigation</u>

Concurrent and in accordance with the passage of Act 200, the PUC issued Order No. 35566 ("Order 35566") on July 10, 2018, initiating its Microgrid Investigation in Docket No. 2018-0163. In Order 35566, the PUC noted that:

> On July 10, 2018, the Governor signed Act 200 into law, in which, observing that "Hawaii's residents and businesses are vulnerable to disruptions in the islands' energy systems caused by extreme weather events or other disasters[,]" the Hawaii State Legislature ("Legislature") concluded that [m]icrogrids can [] provide valuable services to the public utility electricity grid, including energy storage and demand response, to support load shifting, frequency response, and voltage control, among other ancillary services[,]" and that "the use of microgrids would build energy resiliency into our communities, thereby increasing public safety and security. The Legislature further emphasized the dual importance of microgrids to "facilitating the achievement of Hawaii's clean energy policies by enabling the integration of higher levels of renewable energy and advanced distributed energy resources[,]" and providing backup power in an emergency, and the ability to "island" or run autonomously to support "a building or set of buildings with emergency power for critical medical equipment, refrigeration, and charging critical communications devices."[79]

On October 30, 2019, following various suspensions and extensions of time in the Intra-Governmental Wheeling Investigation, the PUC issued an order closing that proceeding, noting that "the commission believes it is more productive and efficient to first examine distribution-level wheeling, including the appropriate level of compensation, in the specific and limited microgrids context"[80] that is the subject of the ongoing Microgrid Investigation. In closing the Intra-Governmental Wheeling Investigation, the PUC specifically noted the Legislature's statement in Act 200 that "[t]he natural energy laboratory of Hawaii authority is recognized as having the potential to operate a microgrid and may be designated as the first microgrid demonstration project after the establishment of the microgrid services tariff . . . ."[81]

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[78] HRS § 269-46(c).
[79] Docket No. 2018-0163, Order No. 35566 (Haw. P.U.C., July 10, 2018) at 2-3.
[80] Docket No. 2007-0176, Order No. 36710 (Haw. P.U.C., October 30, 2019) at 5.
[81] <u>Id.</u> at 4.

1. Intervenors and Issues in the Microgrid Investigation

On November, 21, 2018, the PUC granted intervenor status in the Microgrid Investigation to the following parties:[82]

- Renewable Energy Coalition of Hawaii, Inc. ("REACH");
- Distributed Energy Resources Council of Hawaii ("DERC Hawaii")
- Life of the Land ("LOL");
- Puna Pono Alliance ("Puna Pono");
- Microgrid Resources Coalition ("MRC");
- Energy Island;
- Energy Freedom Coalition of America, LLC ("EFCA"); and
- Ulupono Initiative LLC ("Ulupono").[83]

On January 9, 2019, the PUC convened a technical conference during which the parties to the docket were invited put on presentations regarding: (1) past and ongoing experiences regarding the development of microgrids in Hawaii; and (2) responses to certain preliminary questions from the PUC, namely:

- How should the term "microgrid" be defined for purposes of the MGS Tariff?

- What characteristics of a microgrid (e.g., islanding capability, generation resource types, size, etc.) should be included in the definition of microgrid?

- What ownership structures should be included in the MGS Tariff (e.g., customer-owned, cooperative, third-party, utility-owned, etc.)?

- What microgrid services or functions should be considered in developing the MGS Tariff?

- Should a microgrid owner/operator be required to provide a minimum set of services to its customers/subscribers? If so, identify those services, including level of service, where applicable.

- How should existing tariffs/programs (e.g., Smart Export, Demand Response, CBRE, etc.) be coordinated and harmonized with the MGS Tariff, if at all?

- How should interconnection standards and procedures be modified, if at all, to enable the safe and reliable integration of microgrids with Hawaii's electric grids (including development of new standards and procedures if necessary)?

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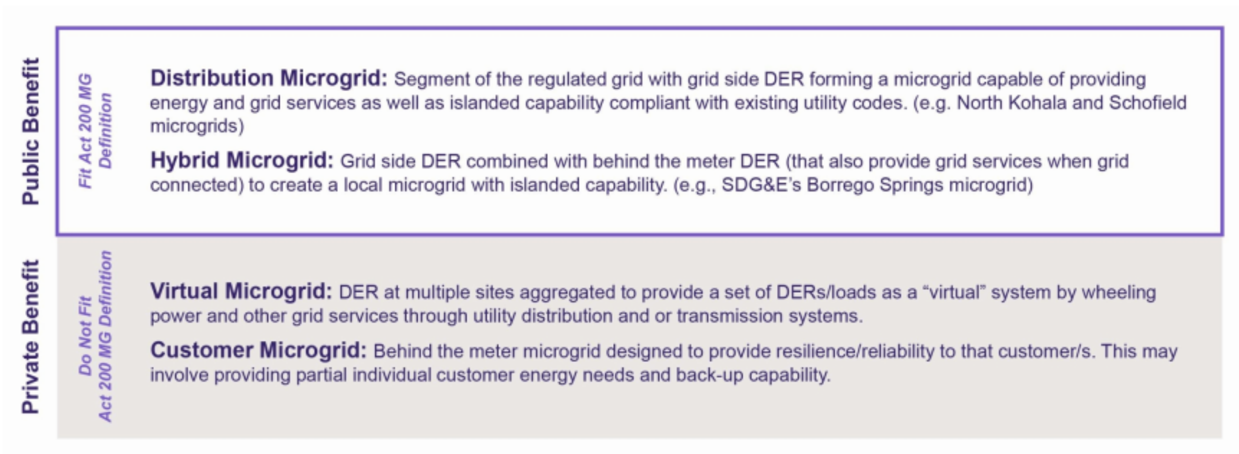
[82] See Docket No. 2018-0136, Order No. 35884 (Haw. P.U.C., November 21, 2018).
[83] REACH, Puna Pono, EFCA and LOL have since withdrawn from Microgrid Investigation.

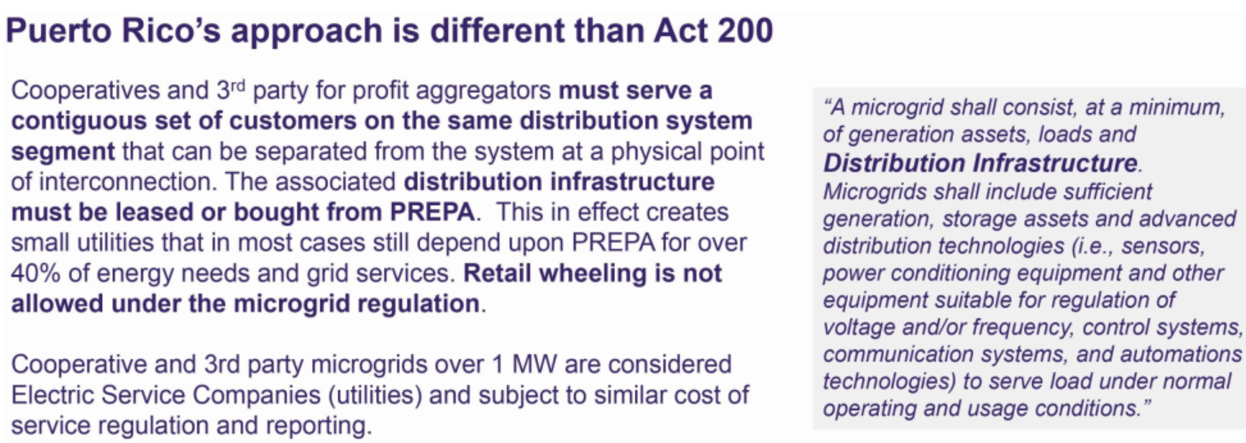
- What other provisions, if any, should be considered in developing the MGS Tariff?[84]

2. Parties' Positions on Wheeling as it Relates to Microgrids

Two of the slides submitted by HECO at the January 2019 technical conference specifically addressed wheeling. As shown below, the first of the two slides set forth HECO's position at the time on the types of wheeling that it considered permissible under Act 200:



HECO's second slide on wheeling compared wheeling in Puerto Rico to wheeling under Act 200:



Following the technical conference, the PUC directed the parties to file briefs regarding their answers to the questions presented, and further requested the parties to:

- map out and identify the existing tariffs and programs already addressing and/or providing guidelines for services relevant to microgrid;

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[84] See Docket No. 2018-0136, Order No. 35884 (Haw. P.U.C., November 21, 2018) at 25-26 (footnotes omitted).

- propose guidelines that should be included in the tariff with respect to interconnection; and

- explain how the HECO's Rule 14.H, *Interconnection of Distributed Generating Facilities with the Company's Distribution System*, would need to be modified, if at all.[85]

As described below, a few of the parties to the Microgrid Investigation alluded to wheeling in their opening briefs:

HECO's opening brief identified "the appropriateness of wheeling for microgrids" as one of the issues that should be considered in the Microgrid Investigation (see id. at 40), asserting that "[s]ystems that rely on wheeling, including virtual microgrids, do not enhance reliability and do not fit the definition of a microgrid for the purposes of the MGS Tariff" (see id. at 41). In support of this position, HECO stated:

> The MGS Tariff is being crafted primarily to enhance resiliency for the benefit of the public, whether during normal grid-connected operations or while islanding during an emergency. Therefore, it is important to distinguish those types of microgrids that actually provide public resiliency benefits for the utility grid and its customers from certain types of systems that are designed to benefit only its private owners or customers, without enhancing resiliency. For example, as described in more detail in Exhibit 9, some developers are promoting a set of systems under the banner of microgrids, which are sometimes referred to as "virtual microgrids" or "multi-user microgrids." However, those systems require connections to the grid and rely upon wheeling power from the supply resource across the utility distribution system to specific customers. Not only do these systems not enhance resiliency, they instead depend upon the utility grid resources—paid for by the utility ratepayers—in order to bypass utility retail service for private gain. As a result, these types of systems do not add to the resiliency of the grid during normal operations and cannot effectively island without causing safety problems or other operational impediments, which are described in Exhibit 9. Therefore, these types of virtual or similar systems that rely upon wheeling do not enhance resilience and do not fall within the definition of a "microgrid" subject to the MGS Tariff.
>
> By contrast, we note that similar but fundamentally different microgrids referred to as "community microgrids" are able to serve critical community infrastructure during emergency operations and increase the resilience and reliability of the utility grid during normal operations. As the name suggests, community microgrids are systems designed to serve multiple customers located within a community, typically including critical

[85] See Docket No. 2018-0163, Order No. 36106 (Haw. P.U.C., January 22, 2019).

> infrastructure, by providing renewables-based emergency power during periods of utility grid outages. Community microgrids are integrally connected to a utility distribution network, capable of supporting safe islanding, and do not rely upon wheeling. As described in Exhibit 9, the planning process and compensation programs already exist or are in development in Hawaii to support community microgrid development. Therefore, all of the claimed public benefits of virtual or multi-user microgrids can be achieved via properly integrated community microgrids, which fit the definition of a microgrid and do not require wheeling, with all of its inherent inequities.

Id. at 40-41 footnotes omitted; see also Hawaiian Electric's Reply Brief at 41, 43.

The opening brief jointly filed by Energy Island, LOL and Puna Pono suggested that issues related to wheeling at the HOST Park might be appropriately addressed in the Microgrid Investigation, noting that:

> The Natural Energy Laboratory of Hawaii Authority ("NELHA") originally sought to wheel power for their seawater pumping / piping system and possibly power the adjacent Ellison Onizuka - Kona International Airport. Such legislation is in place, however, some clarification is still needed and it is hoped, that is resolved within this docket. Obviously for any familiar, an electrical microgrid fits most naturally with this closed- and open looped seawater system that provides over $100 million in economic development per year. (Id. at 5.)

The opening brief filed by the Consumer Advocate also referenced (but did not cite or elaborate on) a section of HRS Chapter 269 providing that, "Nothing in this section shall be construed to permit wheeling." (Id. at 23.) This appears to have been a reference to the definitions section of Hawaii's Public Utilities law (see HRS § 269-1(2)(N)(vii)), and may be an indication of the Consumer Advocate's general opposition to wheeling.

3. PUC's Observations

On August 20, 2019, the PUC issued Order No. 36481 in the Microgrid Investigation *(1) Prioritizing Items for Resolution in this Docket and (2) Making Determinations of Issues Raised by the Preliminary Questions in Order No. 35884* ("Order 36481"). Based on the feedback provided in the parties' briefs, the PUC included seven general observations in Order 36481, which are listed in turn below.

1. "Improving Resiliency is a Primary Focus of Act 200 and should be the Initial Priority of Microgrid Services Tariff."[86]

[86] Docket No. 2018-0163, Order No. 36481 (Haw. P.U.C., August 20, 2019) § III.A.1.

2. "Current Programs and Interconnection Rules Provide Pathways to Develop Microgrids but May Limit Multi-Customer Applications."[87]

3. "Multi-Customer Microgrids Currently Do Not Appear Feasible Without Direct Utility Participation."[88]

4. "Current Interconnection Standards for Microgrids Lack Standardization."[89]

5. "Existing Programs/Tariffs Provide Compensation But May Require Adjustments."[90]

6. "Clarity On Distribution-Level Wheeling Rules Appears Necessary To Facilitate Private, Third-Party Microgrid Development."[91]

7. "Microgrid Demonstration at Natural Energy Laboratory of Hawaii Authority (NELHA)."[92]

Order 36481 did not provide definitive regulatory guidance on whether or to what extent the PUC would eventually allow the wheeling of electricity over a utility distribution line within the boundaries of a microgrid. However, the PUC's observations with respect to resiliency, multi-customer microgrids, distribution-level wheeling and the HOST Park appear particularly germane to a NELHA microgrid project, and are further discussed below.

1. <u>Resiliency as a Primary Focus and Priority</u>

One of the primary purposes of creating a microgrid at the HOST Park is to provide backup power in the event of an emergency. Noting that the preamble of Act 200 discusses the vulnerability of island energy systems to extreme weather events or other disasters, and the role that microgrids can play in building energy resiliency into communities, thereby increasing public safety and security, the PUC stated that:

> To better focus the commission's and Parties' near-term efforts on activities that can support the intent of Act 200, the commission's initial priority in developing the microgrid services tariff is to facilitate applications of microgrids that improve energy resiliency, particularly the islanding of microgrids during emergency events and grid outages to provide backup power to customers and critical energy uses.[93]

The PUC added:

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[87] <u>Id.</u> § III.A.2.
[88] <u>Id.</u> § III.A.3.
[89] <u>Id.</u> § III.A.4.
[90] <u>Id.</u> § III.A.5.
[91] <u>Id.</u> § III.A.6.
[92] <u>Id.</u> § III.A.7.
[93] Docket No. 2018-0163, Order No. 36481 (Haw. P.U.C., August 20, 2019) at 48.

> [G]iven the priorities established by Act 200 and the remaining vulnerabilities of Hawaii's energy systems to extreme events, the focus for the remainder of this docket is to facilitate the ability of microgrids to island and provide backup power to customers and critical energy uses during contingency events.[94]

In light of the PUC's focus on resiliency, the case for a proposed microgrid project at the HOST Park may benefit from an emphasis on resiliency as a key benefit of the project.

2. Direct Utility Participation in Multi-Customer Microgrids

One of the potential issues with a microgrid project at the HOST Park is that the HELCO line serves multiple customers. With respect to such situations, the PUC observed:

> Based on the Parties' briefs and responses to the commission's Preliminary Questions, a group of customers (or accounts owned by same customer) that desire to utilize their DERs to supply critical loads during an emergency or sustained outage do not appear to have clear pathway to use these resources for backup power, unless the utility is directly participating in the project, such as the Schofield Barracks Generation Station project. This appears to be a potentially significant limitation on future development of microgrids whether the project is designed to support facilities with broader public benefits or solely for private use during an outage.[95]

Based on the PUC's discussion above, it appears that the viability of a proposal for a microgrid project at the HOST Park may benefit from utility participation in the project. It is also noteworthy that whereas HECO has been somewhat skeptical of "systems that are designed to benefit only [a microgrid's] private owners or customers"[96] the PUC did not foreclose the possibility of a microgrid that is designed "solely for private use during an outage."

3. Distribution-Level Wheeling for Microgrids

As discussed above, the distribution of customer-generated electricity among customers on HECO's distribution system at the HOST Park presents potential wheeling issues. In this regard, the PUC observed:

> The lack of any rules or tariffs to utilize existing utility distribution infrastructure currently prohibits group of customers with interconnected loads and DERs that meet the definition of microgrid project (i.e., act as single controllable entity that could disconnect from the grid in island mode) to act as microgrid and provide service to those customers inside the microgrid during certain events. This present situation does not appear consistent with Section 269-46(b) which states, "Any person or entity may

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[94] Id.
[95] Id. at 49-50.
[96] See Section III.C, supra.

> own or operate an eligible microgrid project or projects; provided that the person or entity complies with all applicable statutes, rules, tariffs, and orders governing the ownership and interconnection of the project or projects." Section 269-46 also makes clear that the microgrid services tariff needs to provide fair compensation for electricity, electric grid services, and other benefits provided to, or by, the electric utility, the person or entity operating the microgrid, and other ratepayers.[97]

Significantly, the PUC added in its determinations regarding priority items in Order 36481 that, "The commission is open to considering wheeling of power during these conditions to support resilience during outage events"[98] and "is supportive of reducing or removing regulatory barriers to private investment in microgrids when primary benefits accrue to microgrid participants . . . ."[99]

4. <u>NELHA Microgrid Demonstration</u>

A potential microgrid project at the HOST Park was specifically mentioned in Order 36481. In this regard, the PUC observed:

> Section 4 of Act 200 notes potential opportunities for microgrid demonstration projects at NELHA. NELHA is a not party to this proceeding but representatives working on a demonstration project at the site did participate in the January Technical Conference. The commission is supportive of demonstrations at the NELHA facility to test advanced technologies and market concepts that can facilitate microgrid development consistent with the purpose of Act 200. To the extent regulatory flexibility is necessary to test these applications, the commission is open to proposals from NELHA and the HECO Companies that would support these projects and further the objectives of Act 200.[100]

The PUC added:

> Consistent with Act 200, the commission recognizes NELHA's facility and HOST tech park as a potential demonstration site for advanced technologies and commercial applications that can facilitate resiliency through microgrid development. If NELHA and/or the HECO Companies wish to request regulatory flexibility to support demonstration project(s) consistent with the intent of Act 200, specific requests can be made in the instant docket while open. The commission does not guarantee that the proposal(s) will be approved, but generally supports opportunities for regulatory flexibility at

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[97] Order 36481 at 51-52.
[98] <u>Id.</u> at 54.
[99] <u>Id.</u>
[100] <u>Id.</u> at 52-53.

this specific site that can facilitate microgrid applications that improve resiliency of Hawaii's energy systems.[101]

D. <u>Draft Microgrid Services Tariff</u>

In addition to setting forth observations and determinations on preliminary questions, Order 35884 requested the parties to form working groups to, among other things, collaborate on the development of a draft MGS Tariff.[102]

On September 12, 2019, the PUC issued an order establishing a procedural schedule for the remainder of the Microgrid Investigation proceeding, including technical conferences, status conferences, draft tariff and Rule 14H updates and comments thereupon, in the 2019-2020 timeframe. On March 30, 2020, HECO filed its *Draft Microgrid Services Tariff*. On April 27, 2020, the Consumer Advocate, MRC and Ulupono filed comments on the draft MGS Tariff. On November 30, 2020, the PUC held a technical conference to discuss the draft MGS Tariff with the remaining parties in the docket. By letter dated December 10, 2020, the PUC directed the parties to reconvene their working group to revise the draft MGS Tariff and related documents, and to file proposed revisions, which were submitted on February 1, 2021. Comments on the proposed revisions and responses thereto were filed on February 10 and 17, 2021, respectively.

E. <u>Decision and Order No. 37786</u>

On May 17, 2021, PUC issued Decision and Order No. 37786 ("D&O 37786") ruling on what it characterized as "Phase 1" of its Microgrid Investigation, in which it approved the draft MGS Tariff (subject to modifications) and directed HECO to file its modified MGS Tariff (and related changes to other affected tariffs) by May 27, 2021.[103] In accordance with D&O 37786, HECO filed a revised version of the MGS Tariff on May 27, 2021, along with related modifications to the following rules for distributed energy resources ("DER Rules"):

- Rule No. 14H – Interconnection of Distributed Generating Facilities with The Company's Distribution System;
- Rule No. 18 – Net Energy Metering;
- Rule No. 22 – Customer Self Supply;
- Rule No. 23 – Customer Grid Supply;
- Rule No. 24 – Customer Grid Supply Plus;
- Rule No. 25 – Smart Export;
- Rule No. 26 – Community-Based Renewable Energy Program; and
- Rule No. 27 – Net Energy Metering Plus.

The modifications to the DER Rules above are substantially similar, and generally add the following section to the respective rules:

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[101] <u>Id.</u> at 59.
[102] <u>See</u> Order 35884 at 55-58.
[103] <u>See</u> Docket No. 2018-0163, Order No. 37786 (Haw. P.U.C., May 17, 2021).

MICROGRIDS

1. Capitalized terms used in this section are as defined in Rule No. 30, Microgrid Services Tariff.
2. During Grid-Connected Mode, the Microgrid will be operated in parallel with the Company's System.
3. A Customer may operate its Generating Facility as part of a Customer Microgrid or be a participant in a Hybrid Microgrid.
4. A Customer who intends to operate its Generating Facility within a Customer Microgrid, or as a participant in a Hybrid Microgrid, shall notify the Company in its application through the Customer Interconnection Tool.
5. A Customer who operates its Generating Facility as part of a Microgrid after obtaining interconnection approval from the Company shall update its application through the Customer Interconnection Tool. Such notification and revision shall satisfy the Customer's notice requirements set forth in Tariff Rule 3B (Change in Customer's Equipment or Operations).
6. Customer Microgrids and Hybrid Microgrid Participants shall comply with the requirements of Rule No. 30, Microgrid Services Tariff, including Section H, Microgrid Operation.

Significantly, the PUC indicated in D&O 37786 that it "<u>accepts the provisions of the [MGS Tariff] allowing wheeling, with no direct compensation</u>."[104] It should be noted, however, that the Microgrid Investigation remains ongoing, and the PUC has indicated that it intends to issue a procedural order to govern a forthcoming "Phase 2" in which certain unresolved issues regarding the MGS Tariff will be addressed. In that the MGS Tariff is subject to change in Phase 2, there is no definitive regulatory guidance to date on whether a microgrid at the HOST Park would fit within the confines of the MGS Tariff, once finalized. Nonetheless, some of the key elements of the latest MSG Tariff published by HECO are discussed below.

1. <u>Two General Categories of Microgrids</u>

Under the revised MGS Tariff, eligible microgrids generally fall into one of two categories, depending on whether they use utility infrastructure: (a) Customer Microgrids; and (b) Hybrid Microgrids.

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[104] D&O 37786 at 27 (emphasis added).

a. **Customer Microgrids**

As defined under the MGS Tariff, a "'Customer Microgrid' is a Microgrid that uses non-utility infrastructure on the customer side of the Point of Common Coupling (PCC), including distribution lines and related equipment, to meet its interconnected loads."[105]

One of the key features of a Customer Microgrid is that, "A Customer Microgrid may intentionally enter into and out of Island Mode on a scheduled or unscheduled basis."[106] In order to compensate the utility for Customer Microgrids having this ability, earlier versions of the draft MGS Tariff provided that "Customer Microgrids shall be subject to Schedule SS (Standby Service) . . . ." However, in D&O 37786, the PUC struck the Schedule SS clause, concluding that "it is not necessary to include a Standby charge at this time.

With respect to compensating customers of Customer Microgrids, the MGS Tariff provides that "all applicable energy credit rates and compensation under existing applicable programs, Customer tariff(s), and rate schedules will apply to the Customer of the Customer Microgrid during Grid-Connected Mode. . . ."[107] In a situation where the operator of a Customer Microgrid provides energy to other customers within the microgrid boundary, the MGS Tariff provides that the operator "may allocate costs without markup for electric service received from the Company to other persons within the electrical boundaries of the microgrid who have contracted to receive service from the microgrid."[108]

b. **Hybrid Microgrids**

As defined under the MGS Tariff, a "'Hybrid Microgrid' is a Microgrid that uses utility and non-utility infrastructure on the Microgrid's side of the PCC, including distribution lines, Generating Facilities, and related equipment to meet its interconnected load."[109]

Unlike a Customer Microgrid (which may enter into and out of Island Mode on a scheduled or unscheduled basis), a Hybrid Microgrid may enter Island Mode "only under (1) Emergency Events, or (2) as otherwise permitted or directed by the Company."[110] In order to compensate the utility for the use of its distribution infrastructure, earlier versions of the MGS Tariff required Hybrid Microgrid operators to pay the utility "a $5/kW AC Program Administration Fee (annually), from the Commercial Operations Date[.]" However, in D&O 37786, the PUC struck the provisions for microgrid operator fees, explaining only that "no other Parties provided comment on or proposed revisions to this provision."[111]

The use of utility infrastructure while operating in both Grid Connected Mode and Island Mode introduces additional layers of regulatory complexity not present in Customer Microgrids.

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[105] MGS Tariff § A.1.i.
[106] Id. § H.3.
[107] Id. § E.1.a.
[108] Id. § B.4.a.
[109] Id. § A.1.p.
[110] Id. § A.1.u.
[111] See D&O 37786 at 54-55.

For example, in order to limit the impacts of Hybrid Microgrids on the utility's overall electric system, Hybrid Microgrids are subject to size limits not applicable to Customer Microgrids. In this regard, the MGS Tariff provides that, "The Total Peak Demand for Hybrid Microgrids utilizing the Hybrid Microgrid Agreement . . . cannot exceed . . . 1 MW (AC) on Hawaii Island. A Microgrid with a Total Peak Demand greater than the specified limit [is] not eligible under this tariff."[112] However, footnote 2 of the MGS Tariff provides an exception to this rule, stating that, "Hybrid Microgrids with a Total Peak Demand greater that the specified limits may be proposed to the Utility for Public Utilities Commission approval. Generating resources and development of such projects may require Power Purchase Agreements."

The greater interaction with the utility under a Hybrid Microgrid scenario gives rise to other heightened administration requirements as well. For example, the operator of a Hybrid Microgrid is required to submit a *Hybrid Microgrid Application* to the Company that includes "information to govern the expected performance and operation of the Hybrid Microgrid during, and leading into, Emergency Events, as well as transitioning to and from Island Mode to Grid-Connected Mode."[113] With respect to users within the microgrid boundary other than the microgrid operator, a Hybrid Microgrid is subject to additional requirements related to "Microgrid Participants," which are defined as "Customer[s] that ha[ve] executed the appropriate documents with the Microgrid Operator to participate in the Hybrid Microgrid in which the Customer[s are] located."[114] These include requiring the Hybrid Microgrid operator to complete "Disclosure Checklists" with each of its Microgrid Participants and submit them to the Company as part of the Microgrid Application process.[115] Hybrid Microgrids are also subject to additional monitoring and reporting requirements not applicable to Customer Microgrids.[116]

Billing and compensation for Hybrid Microgrids are also more complicated than for Customer Microgrids. In this regard, the MGS Tariff provides:

> <u>Compensation for Hybrid Microgrid Operator and Microgrid Participants</u>.
>
> a. For a Hybrid Microgrid Operator and all Microgrid Participants, all applicable energy credit rates and compensation will apply during Grid-Connected Mode and Island Mode. <u>While operating in Island Mode, all existing applicable Customer tariffs and programs shall remain in effect and all energy delivered and sold within the Microgrid during the period will be deemed transacted with the Company pursuant to the tariffs</u>.
>
> b. Any Generating Facility with an appropriate Customer Interconnection Agreement executed with the Company and supplying energy to a Hybrid Microgrid during Island Mode, and without an existing means for compensation by the utility (e.g., PPA, tariff)<u>, shall be compensated</u>

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[112] MGS Tariff § D.2.
[113] <u>Id.</u> § G.4.
[114] <u>Id.</u> § A.1.w.
[115] <u>Id.</u> § G.
[116] <u>Id.</u> § H.5.

by Energy Credit Rates as defined and outlined in Rule No. 24 for energy supplied during Island Mode only.

c. Customers within a Hybrid Microgrid shall be billed monthly for the energy supplied by the Company, in accordance with Rule No. 8, the applicable rate schedule, and Company's rules filed with the Commission.[117]

The reference to Rule No. 24 above is in relation to HECO's *Customer Grid Supply Plus* ("CGS+") program, under which customers receive a monthly bill credit for energy delivered to the grid, which helps to offset the cost of energy received from the grid when the system is not producing enough energy to meet the customer's demand. The general mechanics for metering and billing under the CGS+ Program are set forth in Section C.4 of the CGS+ tariff, which provides:

> The measurement of the kWh supplied by the Company to the Customer-Generator and the kWh received by the Company from the Customer-Generator shall begin on the date of installation of the required meter(s) or Company's approval to interconnect the Generating Facility, whichever comes later. For each billing period, the kWh received by the Company shall be assigned to kWh credits applied to calculate the current bill ("Credits Applied") and/or to kWh credits carried over to the future billing period(s) within the current 12-month period ("Banked Credits"). The Company shall assign to kWh Credits Applied the amount of kWh received up to the amount of the kWh supplied by the Company. Any kWh received by the Company in excess of the kWh supplied by the Company shall be added to kWh Banked Credits. The balance of kWh Banked Credits shall be reduced by any kWh Banked Credits Applied . . . ."

For Hawaii Island, the Energy Credit Rate is fixed at 10.55 cents per kWh through October 20, 2022, and subject to modification by the PUC (see Rule No. 24 Section C.5). Pursuant to Section C.1 of the CGS+ Tariff:

> The Company, at its expense, may install meter(s) to record the flow of electric power in each direction. The Eligible Customer-Generator shall, at its expense, provide, install and maintain all conductors, service switches, fuses, meter sockets, meter instrument transformer housing and mountings, switchboard meter test buses, meter panels, and similar devices required for service connection and meter installation and operation on the customer's premises in accordance with the Company's Rule No. 14, Section A.2.

[117] Id. § E.2.

2. Unresolved Issues for Phase 2

As noted above, the MGS Tariff is subject to change in Phase 2 of the Microgrid Investigation proceeding. As stated by the PUC, “These additional topics include, but are not limited to: (1) . . . appropriate compensation for services; (2) expanding the operation of microgrids to non-emergency situations; and (3) further collaboration on streamlining the Microgrid Services Tariff, including added generation applications.”[118]

D&O 37786 also includes an express offer from the PUC for NELHA’s participation in Phase 2 of the Microgrid Investigation. As stated by the PUC:

> The Commission notes that NELHA recently announced the design and construction of “an advanced microgrid featuring artificial intelligence (AI), advanced photovoltaic (PV) solar panels and battery storage at the Hawai‘i Ocean Science and Technology Park (HOST Park) which is administered by the Natural Energy Laboratory of Hawai‘i Authority (NELHA).” The Commission is encouraged by NELHA’s progress in developing project, and invites NELHA to review the Hybrid Microgrid Tariff approved herein. The Commission welcomes feedback or alternative proposals in Phase 2, consistent with Act 200.

F. Microgrid Considerations at the NELHA HOST Park

HNEI’s Grid***START*** team has worked with NELHA to analyze the feasibility and benefits of modifying the current energy system at NELHA’s HOST Park to enable it to operate as a microgrid (or a number of microgrids), connected to HECO’s Hawaii Island electric system or as a stand-alone facility. The objectives of this effort were to: (1) identify distribution system configurations that optimize economic, reliability and resiliency benefits to both the HOST Park distribution system and the broader Hawaii Island electric system; and (2) maximize the use of existing and potential renewable energy resources at the HOST Park in furtherance of State energy policy goals (including Hawaii’s RPS and Net Zero goals).

1. Configuration of the HOST Park Distribution System

As shown in Figure 1 below, NELHA currently has four existing metered accounts at the HOST Park (i.e., at the four existing transformers) that primarily provide service to NELHA’s: (1) 55-inch Pump Station; (2) Booster Pump Station; (3) Research Campus; and (4) Farm Compound. As currently configured, the Booster Pump Station, Research Campus and Farm Compound are capable of being isolated from the HECO system (and operated as a microgrid or microgrids using backup diesel generators) by opening a single switch that is situated between the 55-inch Pump Station and NELHA’s downstream end of the HOST Park distribution system (“Switch”). However, due to its location on the HECO system’s upstream side of the Switch, the 55-inch Pump Station (which also has its own backup diesel generator) is not currently capable of being isolated by opening the Switch.

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118 See D&O 37786 at 61-66.

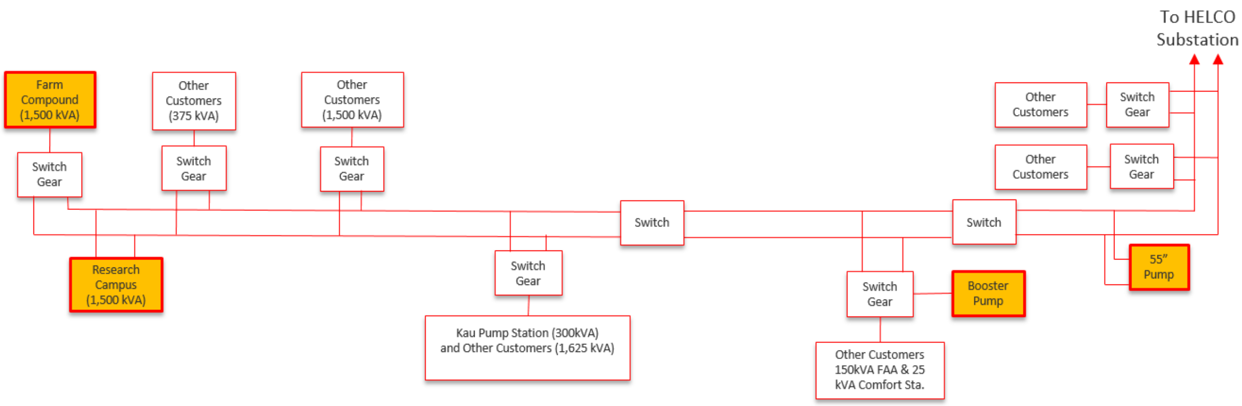

Figure 1 – Existing HELCO 12kV service to the four NELHA HOST Park metered accounts.

As shown in Figure 2 below, if the 55-inch Pump Station's connection to the HOST Park distribution system were moved from HECO's upstream side of the Switch to the HOST Park's downstream side of the Switch, the entire HOST Park load could be isolated by simply opening the Switch. In the event of an outage, this would enable the HOST Park's critical loads to be safely served by the facility's backup generators and renewable energy resources while completely isolated from the HECO system. The benefits of such a "natural" microgrid configuration include increased reliability and resilience for loads within the HOST Park, increased opportunities to cost-effectively leverage renewable energy resources, the ability for HECO crews to more safely and simply isolate HOST Park loads in the event of an outage, and (as recognized by the PUC) an opportunity for collaboration between NELHA, HECO and its regulators to demonstrate and test advanced technologies and commercial applications that can facilitate microgrid development consistent with the purpose of Act 200.

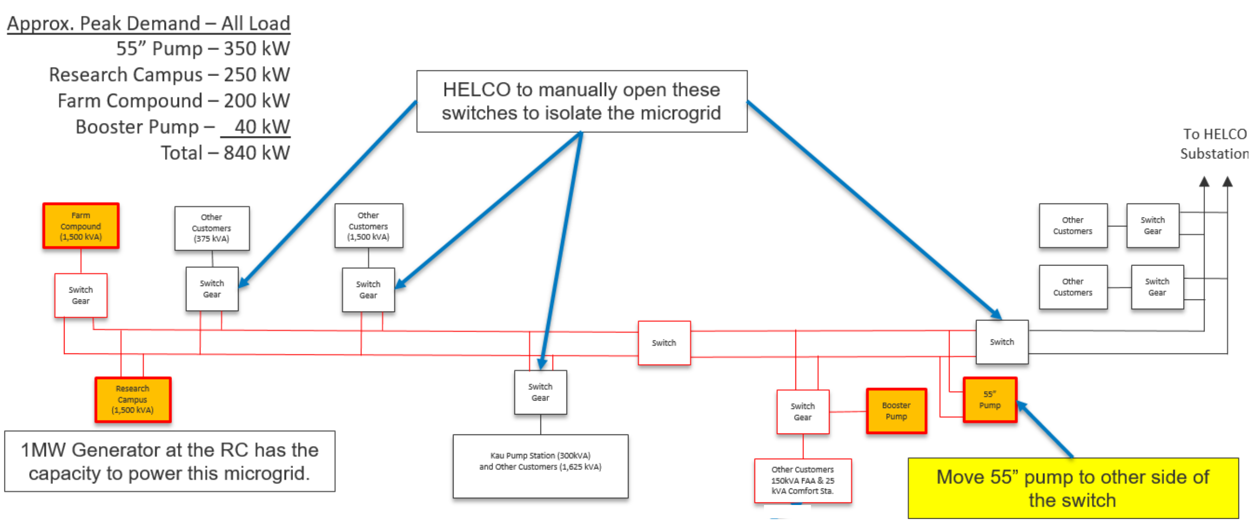

Figure 2 – NELHA HOST Park 55" Pump Station load relocated "downstream" of HELCO switch.

Portions of the existing distribution system within the HOST Park are owned by HECO. Where this is the case, the creation of a NELHA-operated microgrid may require NELHA to either expand its own distribution system or to use the utility's distribution infrastructure within the park during outages.

Under the circumstances, it appears that it would be much more reasonable and in the public interest for NELHA to leverage HECO's existing distribution facilities that are already in place at the HOST Park. First, it would not make economic sense for the State to expend substantial amounts of money to duplicate existing infrastructure that would only be used in the rare event of an outage. In addition, in that the HOST Park microgrid would only be operated during outages (i.e., when HECO's distribution lines are de-energized), there should not be any "wheeling" or other operational-type issue with a third-party utilizing property that is currently "used or useful" for utility purposes. Moreover, from a customer perspective, the net cost to utility customers of allowing the HOST Park to utilize HECO's distribution system during rare outage events would be *de minimus* at most; in fact, Hawaiian Electric's ability to more safely and efficiently isolate the HOST Park from Hawaii Island grid during outages may even reduce costs to customers. Further, continuing to bill customers for electric service at the HOST Park will help the utility to continue financing its fixed costs of service that are ultimately passed to customers.

2. Applicability of the MGS Tariff to a HOST Park Microgrid

The applicability of the MGS Tariff to a NELHA-operated microgrid at the HOST Park will likely depend on a number of factors. A microgrid at the HOST Park would only qualify as a "Customer Microgrid" if it did not use utility infrastructure within its boundaries. It appears that his could be achieved in one of two ways. One approach would be to design the microgrid in a manner that does not rely on any HECO-owned infrastructure – for example, by confining it to the Research Campus and Farm Compound areas where NELHA owns the distribution infrastructure. A second more costly approach would be to install NELHA-owned distribution infrastructure to connect the Research Campus and Farm Compound loads to the 55-inch Pump Station and Booster Pump Station loads, thereby forming a single Customer Microgrid to serve the entire HOST Park. As discussed above, some of the benefits of a Customer Microgrid *vis a vis* a Hybrid Microgrid are that Customer Microgrids are not subject to program limits and are relatively simple to administer.

In contrast to a Customer Microgrid, a "Hybrid Microgrid" at the HOST Park would not be constrained by a prohibition on the use of utility infrastructure on NELHA's side of the PCC. However, a key limiting factor for implementing a Hybrid Microgrid at the HOST Park may be the Big Island's 1 MW maximum limit on Total Peak Demand for microgrid. A potential way of addressing the 1 MW limit may be to exclude certain HOST Park loads from the Hybrid Microgrid, or even by breaking the project into two separate microgrids – each with a total peak demand of less than 1 MW.

If neither the "Customer Microgrid" nor the "Hybrid Microgrid" solutions are capable of meeting NELHA's needs at the HOST Park, consideration may be given to proposing an "Alternative Hybrid Microgrid." In this regard, the MGS Tariff provides:

> Alternative Hybrid Microgrids. The developer of a proposed Hybrid Microgrid may make a proposal for Microgrids not covered by this Tariff to the Company, which would, if acceptable to the Company, be incorporated in a separate agreement with the Company that is subject to Commission approval.[119]

A key benefit of pursuing an Alternative Hybrid Microgrid may be that it would enable a proposal better suited to NELHA's unique situation at the HOST Park. Unlike Hybrid Microgrids in other areas that would potentially utilize HECO's distribution assets while operating in both Grid Connected Mode and Island Mode, the HOST Park is situated "at the end of the line" within HECO's distribution system, and therefore the HOST Park microgrid would in effect only be using the HECO line for microgrid purposes during outages (i.e., during very rare instances while in Island Mode when the line is not being used for utility purposes). In that NELHA's limited use of this line will not have any impact on customers outside of the HOST Park microgrid, the cross-subsidization concerns typically associated with the "wheeling" of electricity should not be applicable to this situation. Indeed, as noted above, the PUC indicated in D&O 37786 that it "accepts the provisions of the [MGS Tariff] allowing wheeling, with no direct compensation."[120]

3. HOST Park Customers Other than NELHA

Another consideration in the design of a microgrid at the HOST Park is whether NELHA would serve as the microgrid operator for only NELHA-owned loads (i.e., with no other participants). Under such an arrangement, customers within the HOST Park other than NELHA would be disconnected from the microgrid upon entering into Island Mode. A potential advantage of this "operator-only" arrangement is that it could be relatively simple from an administrative standpoint and avoid the time and resources necessary to negotiate with other participants. It is recognized, however, that there may be customers other than NELHA at the HOST Park who desire to participate in a NELHA-operated microgrid. From a demonstration project standpoint, one of the advantages of pursuing the enlistment of Microgrid Participants at the HOST Park *vis a vis* other locations is that NELHA already has working relationships with its tenants and is familiar with their electric loads. In some cases (such as with the Federal Aviation Administration facility), there also may be significant public policy reasons to avoid disconnecting tenants' critical loads.

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[119] MGS Tariff § E.3.

[120] D&O 37786 at 27 (emphasis added).

IV. CONCLUSION

Recent advances in microgrid technologies are presenting valuable opportunities to increase electric system reliability and resiliency, enable the integration of higher levels of renewable energy and distributed energy resources, and provide backup power in emergencies. NELHA's HOST Park provides a natural and ideal test-bed for evaluating microgrid capabilities in Hawaii. Coupled with strong regulatory support from the Hawaii PUC, NELHA is well-positioned to continue its leadership toward the development of cutting-edge microgrids that provide benefits not only to NELHA and its tenants, but also for HECO, its customers, and the State of Hawaii at large. Moving forward, HNEI and its Grid***START*** team look forward to continued collaboration with NELHA on this critically-important work.

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NELHA HOST Park Microgrid Analysis

Task 3.3: Report on Microgrid Design Options Analysis

Task 3.3 - September 8, 2021

DRAFT

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This report was produced as part of extended activities aimed to enhance grid reliability, increase energy assurance, and reduce energy cost and carbon footprint through the assessment of prospective microgrid solutions at the NELHA Hawai‘i Ocean Science & Technology (HOST) Park. This work is funded by NELHA, a self-sufficient State of Hawai‘i agency, and is a product of the Hawai‘i Natural Energy Institute (HNEI), an Organized Research Unit at the University of Hawai‘i at Manoa under University of Hawai‘i award ID 011866-00002.

This report and its analysis were prepared and authored by HNEI’s Grid System Technologies Advanced Research Team (Grid***START***), established to develop and test advanced grid architectures, new technologies and methods for effective integration of renewable energy resources, power system optimization and resilience, and enabling policies.

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LIST OF ACRONYMS

ATS	Automatic Transfer Switch
BESS	Battery Energy Storage System
DBEDT	Department of Business, Economic Development, and Tourism
DER	Distributed Energy Resources
ESS	Energy Storage System
FC	Farm Compound
FCEB	Fuel Cell Electric Bus
Grid***START***	Grid System Technologies Advanced Research Team
HELCO	Hawai‘i Electric Light Company
HNEI	Hawai‘i Natural Energy Institute
HOST	Hawai‘i Ocean Science and Technology Park
IRR	Internal Rate of Return
kV	Kilovolt
kW	Kilowatt
kWh	Kilowatt-hour
NELHA	Natural Energy Laboratory of Hawai‘i Authority
NPV	Net Present Value
PLC	Programable Logic Controller
PoC	Point of Connection
PV	Photovoltaic
RC	Research Campus
SCADA	Supervisory Control and Data Acquisition
UPS	Uninterruptible Power Supply

LIST OF APPENDICES

***** *Appendix I to this report is provided as an electronic file. The volume and level of detail in Appendix I make it difficult to effectively reproduce in 8.5” × 11” hardcopy form.*

EXECUTIVE SUMMARY

Situated at Keāhole Point in Kailua-Kona, the Natural Energy Laboratory of Hawaiʻi Authority's ("NELHA") Hawaiʻi Ocean Science and Technology ("HOST") Park provides an ideal site to demonstrate the feasibility and benefits of using new microgrid technologies to integrate increasing levels of renewable energy, reduce electricity costs and improve system resiliency. In connection with this Task 3.3 Report, the Hawaiʻi Natural Energy Institute's ("HNEI") Grid System Technologies Advanced Research Team ("Grid***START***") team has worked with NELHA to evaluate commercially-viable scenarios with different permutations of energy generation systems and load requirements using the proprietary XENDEE Microgrid Decision Support Platform ("XENDEE"). At a high level, the XENDEE simulations performed in connection with this report consider fixed costs and other variables to derive optimized microgrid designs, including optimized quantities of PV generation and/or battery energy storage.

This report covers four significant electrical loads at the HOST Park: (1) Research Campus; (2) Farm Compound; (3) 55" Pump Station; and (4) Booster Pump Station. Specifically, this report includes evaluations of microgrids to serve the loads of the:

- Research Campus as a stand-alone microgrid;
- Research Campus and Farm Compound as a combined microgrid;
- 55" Pump Station and Booster Pump Station as stand-alone microgrids; and
- 55" Pump Station and Booster Pump Station as a combined microgrid.

In recognition of potential cost constraints associated with battery energy storage systems ("BESS"), each configuration evaluated in this report generally consists of two permutations: (1) an optimized amount of PV generation in a situation where BESSs are not allowed to be utilized (i.e., the "PV-Only" cases); and (2) an optimized amount of PV generation in a situation where BESSs are allowed to be utilized (i.e., the "PV+BESS" cases).

The ultimate microgrid(s) design for the HOST Park will be affected by numerous factors including but not limited to future load and cost assumptions; access to and cost of capital; resiliency needs; logistics; project management preferences; site development and operational permitting; and regulatory considerations. Even without the addition of battery storage or the ability to merge separately metered HOST Park loads, there are significant opportunities to reduce NELHA's electric bills using PV-Only solutions. However, as summarized below, the results of HNEI's simulations in XENDEE highlight even more promising opportunities for merged Research Campus/Farm Compound and 55" Pump Station/Booster Pump Station microgrids utilizing optimized combinations of PV+BESS.

<u>Research Campus-Only Microgrid</u>

Future loads at the Research Campus will differ from historical energy consumption data primarily as a result of: (1) the HNEI hydrogen production station that is currently under development ("Hydrogen Station"); and (2) NELHA's plans to construct a new "Innovation Village" building with a size and load similar to the existing Hale Iako building. As a result, this report considers Research Campus energy consumption under three load scenarios: (1) a low-load case; (2) a medium/mid-load case; and (3) a high-load case.

The evaluation of a microgrid for the Research Campus is also affected by the siting of future PV generation. For purposes of this analysis, first priority for PV siting within a Research Campus microgrid has been assigned to the Innovation Village, the fixed costs of which are assumed to be "sunk" – that is, the cost of electrically connecting the Innovation Village to the rest of the Research Campus will already have been incurred. For PV generation above and beyond what is sited at the Innovation Village, priority is assigned either to: (1) a large but somewhat remote area of open space known as the "Boneyard," in order to realize administrative efficiencies of implementing a single, large project at a single location; or (2) a number of smaller areas prioritized in order of least $/kW cost within the Research Campus itself, in order to avoid the high fixed cost of electrically connecting the Boneyard to the Research Campus.

All of the Research Campus microgrid cases evaluated in this report indicate that NELHA would financially benefit from implementing a Research Campus-only microgrid, with net present values ("NPV") ranging between $906,000 and $1,737,000 (at an assumed cost of capital of 6%), and internal rates of return ("IRR") ranging between 9.7% and 18.5%. The inclusion of a BESS in the microgrid design generally increases the optimized amount of PV that can be accommodated, particularly at higher loads.

From a financial perspective, it would be better for NELHA to prioritize PV sites in the smaller, lower-cost areas within the Research Campus itself. In fact, the cost of interconnecting the Boneyard and Research Campus renders PV generation from the Boneyard economically infeasible (i.e., not optimal for purposes of the XENDEE simulation) under the low-load cases, while reducing IRRs in the high-load cases. That being said, prioritizing PV at the Boneyard results in the largest PV system (1,065 kW) and highest NPV ($1.7 million) of any Research Campus-only microgrid, under the high-load, PV+BESS case.

Assuming that NELHA proceeds with a PV+BESS, Research Campus-only microgrid, the NPVs of the cases analyzed will be positive regardless of whether the actual load ends up being in the low, middle, or high end of the assumed range. If NELHA builds out its microgrid based on the low-load assumption and the actual load is at the high end of the range, the financial results generally improve. Conversely if the microgrid is built out based on the high-load assumption and the actual load is at the low end of the range, the financial results are not as strong, but still positive, representing a "no regrets" solution as long as the actual loads are in the assumed range.

Combined Research Campus/Farm Compound Microgrid

A combined Research Campus/Farm Compound microgrid will likely provide a number of additional benefits to the HOST Park, when compared to the Research Campus-only scenarios discussed above. For example, combining these loads would generally enable the accommodation of greater amounts of PV at lower loads, and larger battery systems to help offset the need for PV at higher loads. From a resiliency standpoint, combining the loads will primarily benefit the Farm Compound, which will be able to take power from the Research

Campus in the event of an outage. However, combining the loads would also benefit the Research Campus, as the optimized amount of available generation and storage would be higher and more diversified under the combined scenario.

From a financial perspective, the NPV of a combined Research Campus/Farm Compound microgrid will be higher than the NPV of a Research Campus-only microgrid in all but two cases: (1) a low-load, PV-Only case where the Boneyard site is prioritized; and (2) a high-load PV-Only case where the smaller PV sites are economically prioritized. (If NELHA chooses to implement a PV+BESS microgrid, both of these cases would be ruled out.) The improved financial metrics are partially a result of electric bill reductions due to combing the loads under Hawaiʻi Electric Light Company ("HELCO") rate Schedule P.

Assuming that NELHA proceeds with a PV+BESS microgrid under this scenario, the NPVs of the cases analyzed will be positive regardless of actual future loads in all but one case. Namely, if the microgrid is built out at economically-prioritized PV sites based on the high-load assumption and the actual load is at the low end of the range, the NPV will be negative (i.e., "out of the money") unless, for example: (1) NELHA can reduce its cost of capital to 3%; or (2) the actual load is at least in the middle of the assumed range. On the other hand, the economically-prioritized, high-load, PV+BESS case also offers the highest potential NPV ($2.2 million) of any scenario evaluated in this study.

<u>55" Pump Station and Booster Pump Station</u>

Unlike the scenarios summarized above for the Research Campus and Farm Compound, the loads of the 55" Pump Station and Booster Pump Station are assumed to remain constant at 2019 levels. However, the 500 kW/760 kWh ENCORED PV+BESS microgrid demonstration project that is currently under construction ("ENCORED Project") has been treated as an "existing" facility in XENDEE, in order to evaluate whether additional PV generation and/or storage (over and above that provided by the ENCORED Project) would provide additional economic value for the HOST Park.

In an unmerged case, the optimized XENDEE solution would add 161 kW of additional PV to the 55" Pump Station (for a total of 661 kW), and 18 kW of PV to the Booster Pump Station. The BESS provided by the ENCORED Project has adequate capacity for the optimized result; therefore, no additional storage is added in either the merged or unmerged cases. The IRRs for the unmerged 55" Pump Station and Booster Pump Station solutions are 9.3% and 17.6%, respectively.

The merged 55" Pump Station/Booster Pump Station solution increases the total PV installation from 679 kW in the unmerged case to 711 kW in the merged case. The cost of the additional PV modestly reduces the IRR of the merged case to 8.9%, but also lowers annual electric bills due to increased utilization of renewable energy, while increasing resiliency.

Resiliency Considerations

NELHA currently meets its resiliency requirements at its three critical load locations at the Research Campus, 55" Pump Station and Booster Pump Station by automatically transferring those critical loads to backup generation at each location. Installing additional PV systems and BESS can be economical at each location as discussed above and can also provide additional resources to support operations during periods of grid outages. However, the complexity of microgrid control systems and the resources themselves increase as the level of optimization increases. Given the relatively low frequency and short duration of the outages experienced at the HOST Park, a more simplified operating scheme is better-suited for the HOST Park microgrids. As such, the resources for each microgrid scenario were optimized for normal operation using the XENDEE tool and not optimized for islanded operation.

The backup generator serving the Research Campus is currently oversized relative to the size of the Research Campus historical load demand. Even with the added load of the Hydrogen Station, it will still be difficult to incorporate PV generation given the manufacturer's recommended minimum turn-down level of the backup generation. As such, operating with the PV system off during islanded operation will likely need to continue.

Combining the Research Campus and Farm Compound loads provides an aggregate load profile that is better matched with the size of the Research Campus's backup generation. It also provides more opportunities to integrate PV and BESS operation with the backup generator. Applying a modest set point on the PV generation with scheduled dispatch of the BESS would be the simplest operational control scheme to integrate the PV and BESS during islanded operation.

The backup generator at the 55" Pump Station is better sized for the load at that location and able to run a little above its minimum load level when islanded during grid outages. There is some opportunity to add PV generation with the backup generation operation during outages, but not much. However, it is HNEI's understanding that the ENCORED Project is planned and designed to add PV and BESS along with an advanced control system that will enable the optimized use during a grid outage of the PV and BESS resources to be installed. This project will provide NELHA with real-world experience operating and maintaining such a control system. NELHA can then determine if it might be worthwhile (relative to prospective cost and complexity tradeoffs) to extend its operational capabilities to the Booster Pump Station and Research Campus/Farm Compound microgrids.

The load at the Booster Pump Station ranged between 17 and 37 kW in 2019. Given that the manufacturer's typical recommended 30% minimum generation level for the 500 kW generator at the Booster Pump Station is 150 kW, there is not enough load to run a PV system with the generator during a grid outage.

As with the Research Campus and Farm Compound, combining the 55" Pump Station and Booster Pump Station loads provides more opportunity to further optimize the operation of those microgrids as a single microgrid, which would also make better use of the microgrid control system being installed for the ENCORED Project.

HNEI considered the potential to create a single HOST Park microgrid that incorporated the four NELHA metered load centers at the HOST Park. Given the locations of existing switches along the two HELCO 12 kV feeders, it is possible to isolate the NELHA metered loads using the switch located between the Booster Pump Station and 55" Pump Station, provided the tap to the 55" Pump Station is moved to the Booster Pump Station side of that switch. While operational details would undoubtedly need to be worked out with HELCO, it is conceivable that in the event of an extended grid outage, HELCO could dispatch its crews to open the noted isolation switch and possibly several additional switches to isolate other HELCO customers on the feeder to create a larger HOST Park microgrid powered by the existing 1 MW backup generator at the Research Campus. However, given the near term installation of the ENCORED Project and the beneficial consolidation of the Research Campus and Farm Compound loads, it is more practical to create two microgrids at this time (a Research Campus/Farm Compound microgrid and a 55" Pump Station/Booster Pump Station microgrid). Potential coordinated switching with HELCO field crews in the rare event of a prolonged grid outage to achieve a single microgrid configuration can be revisited once the ENCORED Project is in operation. That would also be the appropriate time to best assess and evaluate the feasibility of extending the scope of the ENCORED Project controls to integrate the resources at the combined Research Campus/Farm Compound microgrid.

1 Introduction

1.1 NELHA

The Natural Energy Laboratory of Hawaiʻi Authority ("NELHA") is an agency of the State of Hawaiʻi's Department of Business, Economic Development, and Tourism (DBEDT).[1] NELHA's mission is to "develop and diversify Hawaiʻi's economy by providing resources and facilities for energy and ocean related research, education, and commercial activities . . . ."[2] NELHA's 870-acre Hawaiʻi Ocean Science and Technology ("HOST") Park at Keāhole Point in Kailua-Kona, provides support facilities, infrastructure and leasable land, for research, commercial and education applications. NELHA currently provides supporting services in four key areas: (1) seawater systems; (2) aquaculture; (3) analytical laboratory; and (4) advanced energy.

Most critical among the NELHA services is the world's largest seawater delivery system.[3] Three sets of pipelines deliver warm surface water and cold deep seawater from depths as deep as 3,000 feet for various research purposes. NELHA's existing equipment and pipeline infrastructure can pump up to 100,000 gallons of seawater per minute throughout the HOST Park. To ensure uninterrupted services to its tenants (53 tenants as of September 2020), NELHA requires a reliable power supply with sufficient on-site emergency power backup in the unlikely event of power disruptions from the primary electric service provider, Hawaiʻi Electric Light Company ("HELCO"). Although the HOST Park has diesel backup generators for its critical loads, NELHA intends to use its advanced energy testbed to explore commercially scalable renewable energy technologies – such as energy storage systems ("ESS") and microgrids – that increase the HOST Park's energy resiliency and sustainability, decrease its carbon footprint,[4] and support NELHA's goal to "become carbon neutral by 2030."[5] Microgrids that incorporate renewable distributed energy resources ("DER") show promise to accomplish this objective.

The Hawaiʻi Natural Energy Institute's ("HNEI") Grid System Technologies Advanced Research Team ("Grid***START***") has worked with NELHA to analyze the feasibility and benefits of modifying the current energy system at the HOST Park and enable it to operate as a microgrid (or several microgrids), potentially utilizing the existing HELCO-owned distribution system within the HOST Park to distribute NELHA-generated energy. Among other things, this undertaking has included an evaluation of the potential on-site distributed generation, energy storage, power management and control technologies. The results of the previous analyses (see HNEI's Task 3.1 and 3.2 reports) indicate that the HOST Park's energy security, resiliency and renewable requirements can be best met by solar photovoltaic ("PV") generation coupled with battery energy storage systems ("BESS").

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[1] See HRS § 277D-2 (Establishment of the Natural Energy Laboratory of Hawaiʻi Authority).
[2] See Natural Energy Laboratory Hawaiʻi Authority, *Annual Report 2018-2019*, NELHA (2019), available at: https://nelha.hawaii.gov/wp-content/uploads/2020/11/Annual-Report-2018-2019-nelha-tagged-03.pdf.
[3] Id. at 4-6.
[4] Id. at 25-26.
[5] Id. at 4 (Long term action plans – key focus area).

The HOST Park's geographic location, climatic conditions, high solar insolation, and low rainfall, make solar PV an ideal candidate for the HOST Park's energy requirements. In turn, the value of NELHA's solar PV resources could be enhanced by installing BESS(s), which absorb excess solar energy (to be used at a later time), balance electricity demand and supply through peak-shaving and/or load-leveling, support intermittent renewable energy supply, and reduce the HOST Park's electricity bills. In order to determine the optimal amounts of solar PV and BESS to cost-effectively and reliably support the HOST Park's electric loads, HNEI Grid***START*** evaluated a number of commercially-viable scenarios with different permutations of energy generation systems and load requirements using the proprietary XENDEE Microgrid Decision Support Platform ("XENDEE"), which is further described below.

1.2 XENDEE

XENDEE is a microgrid optimization planning tool that evaluates the resiliency and cost-effectiveness of distributed energy systems. XENDEE's algorithms and software virtually test microgrid designs with real-world settings. Through detailed modeling and control of grid infrastructures such as cables, transformers, storage, PV panels and other components required to ensure safe, efficient, and reliable grid operation, XENDEE can run multiple grid architecture scenarios and calculate optimum microgrid design and performance. At a high level, the XENDEE simulations performed in connection with this report consider fixed costs and other variables to derive optimized microgrid designs, including optimized quantities of PV generation and/or BESS.

One of the key attributes of XENDEE is that it is a cloud-based software that avoids the need for costly computing capabilities on the user's side of the interface. For purposes of high-level analyses, XENDEE can use its own solar billing and load data to optimize microgrids based on their applications and geographic locations. Alternatively, users are also able to upload their actual load, billing, and PV performance data into XENDEE, to ensure more fine-tuned results. In the case of HNEI's analyses of microgrid opportunities at the HOST Park, Grid***START*** used the actual load, billing, and PV performance data from the NELHA facility. As further described in Section 2 of this report, Grid***START*** also conducted a substantial amount of independent research to verify the accuracy of the input assumptions (e.g., component costs, inverter performance) applied in its XENDEE optimizations.[6]

[6] Additional information on the *XENDEE Microgrid Decision Support Platform* is available online at: www.XENDEE.com.

2 Simulation/Optimization Assumptions

Modeling in XENDEE, similar to other simulation environments, begins with initial base input assumptions. XENDEE uses these assumptions to generate optimized microgrid solutions. The inputs and assumptions used by Grid***START*** to model microgrids at the NELHA HOST Park in XENDEE's software environment are discussed below.

2.1 Base Microgrid Load Data

This report covers four significant HELCO metered electrical loads at the HOST Park: (1) Research Campus (sometimes "RC"); (2) Farm Compound (sometimes "FC"); (3) 55" Pump Station; and (4) Booster Pump Station. Grid***START***'s review in the Task 3.1 Report of the HOST Park's load and energy data over the last five years indicates that the energy consumption at all NELHA-owned sites has been relatively steady without significant increase. As a result, Grid***START*** applied the HOST Park's year 2019 gross load data with 15-minute resolution as the baseload in its analyses. The net load profiles for each of the four loads above were extracted from HELCO meter data accessed via the utility's customer web portal. The load profile inputs for the four main HOST Park loads are detailed below.

2.1.1 Research Campus Load

The Research Campus has approximately 205 kW_{DC} of rooftop and ground-mounted PV generation with no active ESS. 35 kW_{DC} of this PV generation was serving the Research Campus load throughout the year 2019. The remaining 170 kW_{DC} of the PV system was added to the Research Campus in August 2019, after several test period days in June and July of 2019. Figure 1 below shows the base gross load profile with 15-minute resolution for the Research Campus in 2019. The gross load profile was derived by adding the total monthly energy delivered by the existing PV generation and the recorded net monthly energy consumption of the Research Campus. As discussed in the Task 3.1 Report, the 2019 data included two abnormal short duration spikes in load in January 2019. Those anomalies were removed to simulate everyday conditions and replaced with load data averaged from the days immediately before and after the anomalous spikes. Recorded PV data for the first six months of 2019 was also not available; therefore, 2020 Supervisory Control and Data Acquisition (SCADA) data was used as a proxy to fill in the data gaps.

The HNEI hydrogen production station that is currently under development ("Hydrogen Station") is expected to add considerable demand to the existing gross load within the Research Campus. Currently, the actual amount of this added load is uncertain and could vary significantly based on future hydrogen production. As a result, three alternative load scenarios for the Hydrogen Station (low, medium, and high) are discussed below and have been analyzed in connection with this report. Moreover, following HNEI's submission of its Task 3.1 Report, NELHA informed HNEI that the Research Campus load would increase further due to a new building named the "Innovation Village," discussed in further detail below. The final estimated gross load for the Research Campus was then derived by adding the Hydrogen Station load (three different scenarios) and the new load from the Innovation Village to the baseload from 2019. As explained in Section 2.1.1.1 below, for purposes of this analysis, the final three load profiles for the Research Campus are designated as: (1) "Low load"; (2) "Mid load"; and (3) "High load."

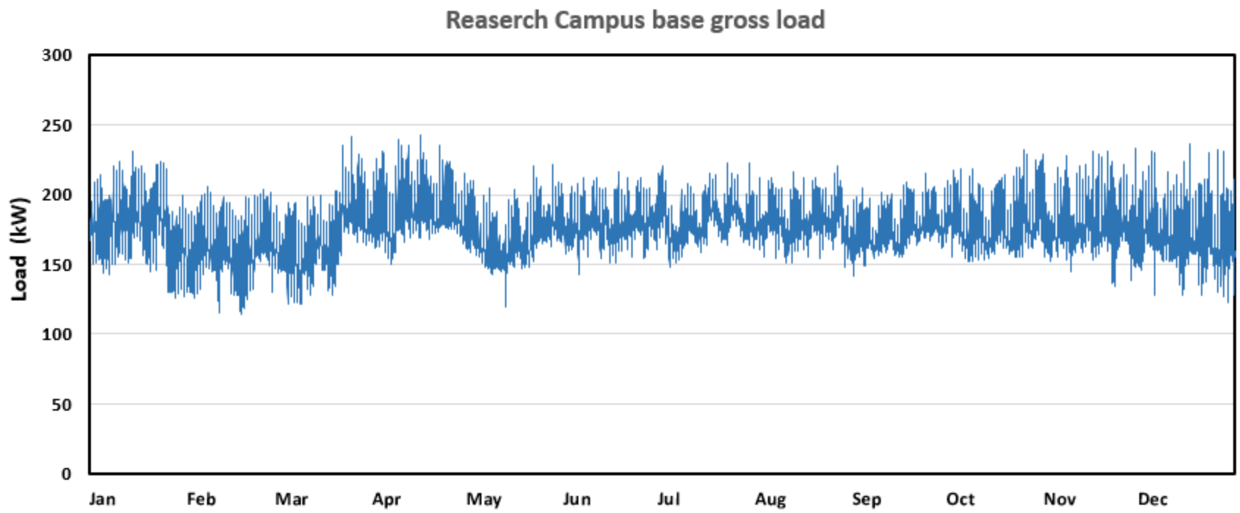

Figure 1: Research Campus Current Gross Load (2019)

2.1.1.1 Additional Hydrogen Station Load (Low, Medium, High)

The Hydrogen Station is a research demonstration project that aims to have an operational hydrogen production and dispensing station to support a fleet of three hydrogen fuel cell electric buses ("FCEB").[7] The station is located in the Research Campus and has an electrolyzer that can produce up to 65 kg of hydrogen per day. The electrolysis of water at the Hydrogen Station uses approximately 65 kWh of electricity per 1 kg of hydrogen production. After the hydrogen is produced through polymer electrolyte membrane electrolysis, it is compressed to 450 psi (atmospheric pressure is 1 Bar or 14.5 psi at sea level) and stored in mobile hydrogen transport trailers that hold up to 102 kg of hydrogen (see Task 3.1 Report, n.4).

One of the FCEB has a 20 kg hydrogen capacity, and each of the two other buses has a 10 kg capacity. The 20 kg capacity FCEB has a range of 200 miles with a full tank of hydrogen, and the 10 kg capacity FCEBs each have a range of 100 miles. Grid***START*** held several meetings with the lead HNEI researcher for the Hydrogen Station project, who proposed three alternative scenarios for hydrogen production and consumption. The three scenarios call for refilling the buses once a week (the low-load case), three times a week (the medium/mid-load case), or five times a week (the high-load case). This equates to the production of 40 kg a week (5.71 kg/day), 120 kg a week (17.15 kg/day) or 200 kg a week (28.57 kg/day), under the low, medium, and high load cases, respectively. The hydrogen production is assumed to occur during the day when solar resources are abundant, and the three alternative daily production levels result in three different electrical load profiles at the Research Campus. An example of the three load profiles is shown in Figure 2 below, where "Low Load," "Medium Load," and "High Load" represent low, medium, and high hydrogen production, generally during daylight hours when

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[7] See Hawai‘i Natural Energy Institute, *Alternative Fuels; Electrochemical Power Systems – NELHA Hydrogen Station and Fuel Cell Electric Buses*, Hawai‘i Natural Energy Institute Highlights (November 2020), available at: https://www.hnei.hawaii.edu/wp-content/uploads/NELHA-Hydrogen-Station-and-FCEB.pdf.

solar PV resources are abundant. An exception to daytime hydrogen production exists for the Medium Load case, where hydrogen production begins at 5:00 AM in order to address decreased production efficiency at levels higher than 130 kW. (The High Load case requires hydrogen production at the station's maximum capacity, and therefore there is no need to commence production before the sun rises.)

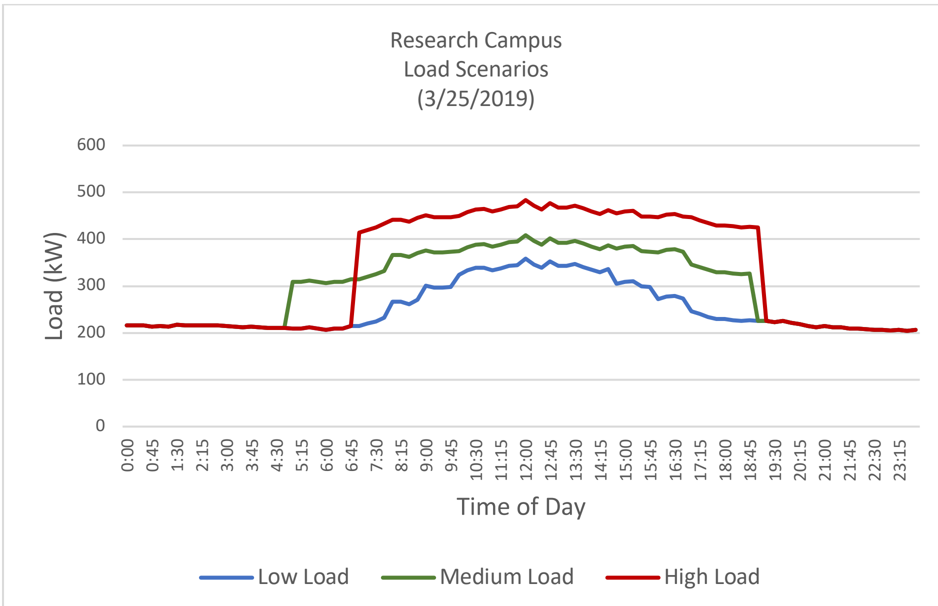

Figure 2: RC Load Scenarios

2.1.1.2 Additional Innovation Village Load

After HNEI submitted its Task 3.1 Report, NELHA informed HNEI of its plans to build a new one-floor "Innovation Village" building with a size and load similar to the existing two-story Hale Iako building. However, the size of the Innovation Village roof will be double that of the Hale Iako building – meaning that it will have room for the installation of approximately 260 kW_{DC} of rooftop PV generation. According to NELHA, the load for the Innovation Village will include the building and typical small industrial loads found in an aquaculture research institute, such as experimental ponds and tanks with aerators and booster pumps. NELHA estimates that the average energy consumption will be 500 kWh/day for the Innovation Village building's internal load and an additional 300 kWh/day for the aquaculture research activities. Therefore, the annual load profile for the Innovation Village building was scaled to the Hale Iako load profile such that daily average energy consumption is 500 kWh/day. 12.5 kW was then added to each data point representing 300 kWh of daily aquaculture-related consumption.

2.1.2 Farm Compound Load

The Farm Compound is one of the main NELHA-owned and -managed load sections at the HOST Park. NELHA does not have any energy generation resources (e.g., solar PV) behind the Farm Compound meter; therefore, the Farm Compound's net load profile is the same as its gross load profile. NELHA has indicated that the electric infrastructure at the Farm Compound is old and will be upgraded and connected to the Research Campus system if NELHA decides to make any system changes within the Farm Compound. In that case, the Research Campus and Farm Compound loads would be combined behind a single meter.

2.1.3 Booster Pump Station Load

The Booster Pump Station has the smallest load profile among all active load sections owned by NELHA at the HOST Park. Like the Farm Compound, the Booster Pump Station currently does not have any behind-the-meter energy generation resources (aside from emergency backup diesel generation). Therefore, for purposes of this analysis, the Booster Pump Station load was modeled using HELCO meter data extracted from its customer web portal, with no further adjustments.

2.1.4 55" Pump Station Load

The 55" Pump Station has the highest load profile among all active NELHA-owned and managed load sections at the HOST Park and currently does not have any behind-the-meter energy generation resources (aside from emergency backup diesel generation). NELHA, in collaboration with ENCORED, Inc., LG Electronics Inc., Seoul National University, Gwangju Institute of Science and Technology, Engie, Coast Energy Capital and HNEI, is currently installing a PV+BESS microgrid demonstration project ("ENCORED Project") at the 55" Pump Station. For purposes of this study, HNEI has utilized the 55" Pump Station's 2019 recorded load data and treated the future ENCORED Project as an existing system in the XENDEE simulations since the project is underway. This assumption enables XENDEE to consider whether an optimized microgrid solution for the 55" Pump Station would benefit from installing additional new PV and/or BESS capacity beyond what is being installed for the ENCORED Project.

2.2 Microgrid Component Cost Assumptions

In general, the minimum components to create a clean, reliable, and cost-effective microgrid are power resources such as solar PV, diesel generators and energy storage. As noted in the Task 3.2 Report, solar PV generation and BESS are the two most viable additional components for microgrids at the HOST Park and are critical for optimizing system size and reducing electricity costs. NELHA currently has diesel generators held in reserve to deliver backup power for its critical loads in the event of a grid power outage.

Concerning PV system assumptions, HNEI consulted three industry resources. Two of the references are engineering firms in the State of Hawaiʻi that design and implement microgrid projects. The third reference was a recently-executed PV+BESS project at the University of Hawaiʻi. Based on these references, HNEI estimates that for projects in the range of hundreds of kilowatts, the average cost for rooftop PV systems is approximately \$2,500/kW_{DC}, and the average cost for ground-mounted PV systems is approximately \$3,000/kW_{DC}. These estimates are inclusive of the cost of the PV inverters, which is approximately \$100/kW. The assumed lifetimes of the PV panels and inverters are estimated to be 25 years and 10 years, respectively. In addition to PV panel and inverter costs, which are variable depending on system size, there are a number of fixed costs that may need to be incurred in order to install a PV system. For purposes of this analysis, these types of "Fixed PV Project Costs" include engineering costs, permitting costs, and any other costs that do not vary directly with the size of the PV system. These costs have been estimated based on information from NELHA and other sources for items such as upgrades that need to be carried out to proceed with different scenarios.

Concerning battery costs, this analysis utilizes the "Battery cost projections for 4-hour lithium-ion systems" from NREL's "Cost Projections for Utility-Scale Battery Storage" report, published in 2019,[8] as a base case. In recognition of the higher costs experienced in Hawaiʻi, NREL's cost projections were then scaled up by a factor of 25%, resulting in an estimated variable battery cost between \$450/kWh and \$500/kWh. Based on further consultations with engineering firms and adding a 10% contingency, \$550/kWh was used as the base cost for new battery additions in HNEI's XENDEE simulations. In line with industry guidance, the useful lifetime for each battery system is assumed to be ten years.

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[8] See Cole, Wesley, and A. Will Frazier, *Cost Projections for Utility-Scale Battery Storage,* National Renewable Energy Laboratory Technical Report NREL/TP-6A20-73222 (2019), available at: https://www.nrel.gov/docs/fy19osti/73222.pdf.

2.3 PV Assumptions

As discussed in turn below, beyond cost assumptions, modeling PV systems in XENDEE requires two additional assumptions: (1) the maximum possible size of the PV system; and (2) technical parameters related to the performance of the PV system.

2.3.1 Available Installation Area

The NELHA HOST Park already has 205 kW_{DC} of existing PV generation at the Research Campus. Available space is an essential consideration in planning for additional PV installations. For purposes of this analysis, HNEI worked with NELHA to identify all of the potential areas for new PV sites in the HOST Park, which are shown in Figure 3 below. Within Figure 3, the areas depicted in yellow and labeled with the letter "A" delineate several suitable PV sites at the Research Campus. The area depicted in red and labeled with the letter "B" delineates a potential site in an area known as the "Boneyard." The area depicted in blue and labeled with the letter "C" delineates a potential site in a large parcel of open space known as the "80 Acre" site. The area depicted in green and labeled with the letter "D" delineates an open parcel of land adjacent to the Wawaloli Beach Park that is known as the "Beach Park" area. The areas depicted in Brown and labeled with the letter "E" delineate two parcels known as the "OTEC" area (on the ocean side) and the "55" Expansion" area (on the mountain side). The area depicted in purple and labeled with the letter "F" delineates a parcel of conservation land known as the "Conservation Land" area.

Figure 3: Potential PV Sites within the HOST Park

A zoomed-in view of the potential PV sites at the Research Campus is shown in Figure 4 below, including the Innovation Village building roof, PV Testbed, NELHA WQL roof, Pipeline Area, Power Building roof, Operational (Ops) building roof, and Covered Parking Area.

Figure 4: Potential PV Sites within the Research Campus

The acreages and system types at the potential Research Campus PV sites are listed in Table 1 below.

Table 1: Research Campus PV Site Details

Location	Size (acres)	System Type
Innovation Village	0.46	Rooftop
PV Test Bed	0.02	Ground-Mounted
NELHA WQL Roof	0.09	Rooftop
Pipeline Area	0.37	Ground-Mounted
Power Building Roof	0.07	Rooftop
Ops Building Roof	0.03	Rooftop
Covered Parking Area	0.17	Rooftop

The acreages and system types at the potential PV sites other than the Research Campus are listed in Table 2 below.

Table 2: Non-Research Campus PV Site Details

Location	Size (acres)	System Type
Boneyard	1.8	Ground-Mounted
80 Acre area	14.7	Ground-Mounted
Beach Park	7.13	Ground-Mounted
OTEC	1.5	Ground-Mounted
55" Expansion	1.87	Ground-Mounted
Conservation Land	6.87	Ground-Mounted

Based on input from industry stakeholders, HNEI has assumed that 1 MW of ground-mounted PV generation requires 3 acres of land. Based on the existing rooftop PV installations at NELHA, HNEI has assumed that 1 MW of rooftop PV requires 1.76 acres of rooftop space. Ground mounted systems require more land due to the spacing required between rows of panels and the space needed for other equipment such as the inverters.

The maximum PV system sizes and associated fixed and variable costs for each potential PV site at the Research Campus are shown in Table 3 below. The second row from the bottom, "Variable Cost ($/kW) (for modelling)," represents the $\$/kW_{DC}$ values that were input as variable costs in the XENDEE simulations discussed in Section 3 below. The remainder of the costs, which do not vary by system size (e.g., electrical tie-in costs), were input as fixed costs in the XENDEE simulations.

The bottom row of Table 3, "All-In Average Cost ($/kW)," allocates the fixed costs associated with each location among the variable cost for each location, in order to rank the overall economics of each site from cheapest (on the left side) to the most expensive (on the right side).

Table 3: Research Campus Fixed and Variable PV Costs by Location
(Research Campus-Only Microgrid)

Research Campus Cost Assumptions	Innovation Village	PV Test Bed	WQL Roof	Pipeline Area	Power Building Roof	Ops Building Roof	Covered Parking Area
PV System Size (kW)	260	8	51	123	40	14	96
PV System Cost ($/kW)	2,500	3,000	2,500	3,000	2,500	2,500	2,500
Electrical Tie-in Costs ($)	---	---	---	55,000	---	---	10,000 (75 sq')
Parking Shade Structure ($) (@ $800/kW) (variable)	---	---	---	---	---	---	76,800
Electrical Upgrades to Existing Infrastructure ($) (fixed)	---	---	---	---	~100,000		
Re-roofing ($) (@ $9.46/sq') (fixed)	---	---	52,000 (5,475 sq')	---	28,850 (3,050 sq')	12,300 (1,300 sq')	---
Site Prep Cost (Grading) ($) (@ $75,000/acre) (variable)	---	---	---	27,750 (0.37 acre)	---	---	---
Variable Cost ($/kW) (for modeling)	2,500	3,000	2,500	3,200	2,500	2,500	3,300
All-In Average Cost ($/kW)	2,500	3,000	3,519	3,600	3,888	4,046	4,071

However, in Table 3 above, row 6 ["Electrical Upgrades to Existing Infrastructure ($) (fixed)"] shows fixed costs associated with electrical upgrades for the existing infrastructure. According to NELHA, these upgrades are necessary only in the case of a Research Campus-only microgrid (i.e., excluding the Farm Compound). If the microgrid serves a combined Research Campus and Farm Compound, this fixed cost would not need to be incurred. In that case, the fixed and variable PV Costs for the various Research Campus locations would change (along with their economized priorities), as reflected in Table 4 below.

Table 4: Research Campus Fixed and Variable PV Costs by Location
(Research Campus plus Farm Compound Microgrid)

Research Campus Cost Assumptions	Innovation Village	PV Test Bed	Power Building Roof	Covered Parking Area	Ops Building Roof	NELHA WQL Roof	Pipeline Area
PV System Size (kW)	260	8	40	96	14	51	123
PV System Cost ($/kW)	2,500	3,000	2,500	2,500	2,500	2,500	3,000
Electrical Tie-in Costs ($)	---	---	---	10,000 (75 sq’)	---	---	55,000
New Shading Area ($) (@ $800/kW) (variable)	---	---	---	76,800	---	---	---
Re-roofing ($) (@ $9.46/sq’) (fixed)	---	---	28,850 (3,050 sq’)	---	12,300 (1,300 sq’)	52,000 (5,475 sq’)	---
Site Prep Cost (Grading) ($) (@ $75,000/acre) (variable)	---	---	---	---	---	---	27,750
Variable Cost ($/kW) (for modelling)	2,500	3,000	2,500	3,300	2,500	2,500	3,200
All-In Average Cost ($/kW)	2,500	3,000	3,220	3,300	3,380	3,519	3,580

The maximum PV system sizes and associated fixed and variable costs for each potential PV site other than Research Campus and Beach Park sites are shown in Table 5 below. (The Beach Park site was ruled out as a viable site for PV at the HOST Park due to its considerable distance from any of the HOST Park load centers and the high cost of connecting it to any of those loads.)

Table 5: HOST Park's Potential PV Sites Outside the Research Campus Area

Non-Research Campus Cost Assumptions	**Boneyard**	**80-Acre Area**	**OTEC Area**	**55" Expansion**	**Conservation Land**
PV System Size (kW)	600	5,650	500	620	2,300
PV System Cost ($/kW)	3,000	3,000	3,000	3,000	3,000
Electrical Tie-in Costs ($)	260,000 (1,050')	1,461,000	---	---	---
Site Prep Cost (Grading) ($) (@ $75,000/acre) (variable)	135,000 (1.8 acres)	2,204,000 (14.7 acres)	112,500 (1.5 acres)	140,000 (1.87 acres)	1,030,000 (6.87 acres)
Site Prep Costs ($) (fixed) (EA=$50,000) (Arch Survey=$25,000) (NPDS=$5,000, if > 1 acre) (SMA Permit=$10,000)	5,000 (NPDS)	80,000 (Arch Survey) (EA) (NPDS)	0*	90,000	0 or 90,000 (0 if priority is given to 55" Expansion)
Variable Cost ($/kW) (for modelling)	3,200	3,400	3,200	3,200	3,450
All-In Average Cost ($/kW)	3,740	3,700	~3,200	3,500	3,500

**A site preparation cost has to be paid once either for the 55" Expansion area or the OTEC Area.*

2.3.2 PV Performance

In XENDEE, solar PV systems are modeled as solar performance curves that define the potential output of the solar PV system. XENDEE can automatically generate solar performance curves based on locational information and insolation data available online from NREL. PV system performance is the total power that can be produced given the solar insolation at any hour of the year and influenced by system efficiency, array and installation type, and tilt. The performance curve is modeled in terms of kW output/kW installed capacity and is assumed to scale with the system's capacity. However, for more accurate modeling, XENDEE also offers users the option of uploading their own PV performance data, where available. For purposes of this study, HNEI uploaded to XENDEE actually-metered PV performance data gathered from the existing PV generation at the HOST Park.

2.4 Battery Assumptions

In addition to cost assumptions discussed in Section 2.2 above, modeling BESSs in XENDEE requires other assumptions such as technical parameters and operational constraints. Further, BESSs can be modeled in XENDEE as a discrete number of battery modules or as a continuous technology, which allows XENDEE to optimize any capacity without being restricted by a module size. The simulations in this study are based on a continuous technology, as this allows XENDEE to optimize any capacity within 1 kWh increments in BESS size.

2.4.1 Available Installation Area

BESS installations require much less area than PV installations. The location for larger BESSs considered in Section 3 below (e.g., with sizing in the range of hundreds of kWh) was discussed with NELHA and a site located adjacent to the Power Building, that is currently occupied by structures planned for removal, could be used to install a large battery system. The smaller BESSs considered below (e.g., < 100 kWh) could even be installed in control rooms or attached to the outside walls of buildings.

2.4.2 Battery Performance

For purposes of this Task 3.3 Report, the parameters used to define BESS performance in XENDEE include roundtrip efficiency, charging and discharging C-rates, and maximum/minimum states of charge ("SOC").

"Roundtrip efficiency" refers to the percentage of energy that can be retrieved from a BESS for every unit of energy placed into the BESS. It is an indication of the level of energy losses associated with a charge/discharge cycle. The range of roundtrip efficiency for BESSs is typically between 75% and 90%.[9] For this report, roundtrip efficiency is assumed to be 90%, which is the efficiency rating for brands such as TESLA.[10]

"C-rates" are maximum safe continuous charging and discharging rates for batteries. In this work, XENDEE's predefined value (0.3) was used for both C-rates. A C-rate of 0.3 means that three-tenths of the BESS energy capacity can be charged or discharged per hour; and therefore, the battery can be fully charged or discharged in 3.3 hours.

SOC is defined as the ratio of the available capacity of a BESS to its maximum capacity. In this study, the minimum SOC was set to 5%, and the maximum SOC was set to 100%, which means that battery SOC could fluctuate between 5% SOC and 100% SOC. The 5% minimum SOC is XENDEE's predefined value for minimum SOC, in order to extend battery life.

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[9] See Steilen and Jorissen, *Hydrogen Conversion into Electricity and Thermal Energy by Fuel Cells: Use of H2-Systems and Batteries*, Electrochemical Energy Storage for Renewable Sources and Grid Balancing (2015), at 143-158, available at: https://www.sciencedirect.com/science/article/pii/B9780444626165000103

[10] See Overall System Specifications, TESLA Power Pack, available at: https://www.tesla.com/powerpack.

2.5 Backup Generator Assumptions

NELHA's backup generators power up automatically once they detect a grid power outage. As discussed in the Task 3.1 Report and listed in Table 6 below, the HOST Park's three major pumping stations and the Research Campus are currently backed up by a diesel generator at each location. The Kau Pump Station is no longer in regular use and is planned for retirement. For purposes of HNEI's microgrid simulations in XENDEE, the backup generators have only been included in the resiliency scenarios discussed in Section 4 below. In those scenarios, the capacity ratings of the backup generators were set equal to the diesel generator sizes. It was assumed that the Research Campus generator could be used as a backup generator for a combined Research Campus/Farm Compound microgrid. The generator's nameplate efficiency and minimum downturn were both assumed to be 30%, based on generator manufacturers' recommendations. The load at the Research Campus is typically less than the 30% minimum downturn level of the 1 MW backup generator at that location and therefore must run below the manufacturer's recommended operating range during a grid outage.

Table 6: List of Diesel Backup Generators

Load section	Manufacturer	Rated capacity (kW)	Fuel tank capacity (gallons)	Age (years)	Approximate fuel consumption (gallons/hour)	Approximate max load run time with a full tank (hours)
Booster Pump Station	Cummins	500	1,000	14	50	20
55" Pump Station	Caterpillar	750	2,500	9	65	38
Kau Pump Station	Caterpillar	125	165	15	9.8	16
Research Campus	Detroit Diesel	1,000	4,000	12-15	77.5	51

2.6 Billing Assumptions

The billing assumptions for the four active HOST Park load sections (excluding the inactive Kau Pump Station) are based on NELHA's year 2019 bills and applicable rate schedules. Table 7 below lists these load sections and their currently applicable rate schedules. HNEI used 2019 tariffs and bills to tune and define the XENDEE simulation model's electric utility tariffs.

Table 7: List of Meters Serving Existing NELHA Load Sections in the HOST Park

Load Section	HELCO Customer ID	HELCO Rate Schedule
Research Campus	NELHA-RES CAMPUS	J
Farm Compound	NELHA-FARM COMPOUND	P
55" Pump Station	NELHA-55" PUMP STN	P
Booster Pump Station	NELHA-BPS3	J

As discussed in Section 3 below, this study has evaluated the viability of consolidating the four load sections above under two meters based on their geographical proximity: (1) a combined Research Campus/Farm Compound microgrid; and (2) a combined 55" Pump Station/Booster Pump Station microgrid. The assumed rate schedules for those scenarios are shown in Table 8 below.

Table 8: List of Meters Serving Combined NELHA Load Sections in the HOST Park

Load Section	HELCO Rate Schedule
Research Campus/Farm Compound	P
55" Pump Station/Booster Pump Station	P

2.7 Financial Assumptions

At a high level, XENDEE optimizes microgrid scenarios based on one of two project financing settings: (1) "Equipment Lifetime Financing"; and (2) "Loan Term Financing". The Equipment Lifetime Financing setting is described as follows:

> DER purchased on the microgrid are amortized over their lifetime. Replacement is assumed at the same purchase price after the DER reach their lifetime. A key to this model is it provides a constant cashflow which repeats indefinitely, which is useful for 1st party microgrids. This is also useful when detailed financing terms are not known, thus is a good step in the design process.

The Loan Term Financing setting is described as follows:

> One loan is taken out over a defined period to finance all or a portion of the microgrid (specified by percentage financed). Replacements are serviced by accruing cash throughout the project, based on the expected replacement cost, only while replacement is needed before the project end. A key to this model provides a changing cash flow over a defined payback period, which is useful for 3rd party microgrids. This is also useful when detailed financing terms are known and can provide accurate economics.

The optimized results under the Equipment Lifetime Financing setting and Loan Term Financing setting are generally consistent, although they may differ slightly in some cases. However, based on the high-level financial information provided to HNEI by NELHA, NELHA's first-party operation and management of the HOST Park, NELHA's planned continued operation into the future of the HOST Park as a going concern, and the planning nature of this study, HNEI elected to run its XENDEE simulations using the Equipment Lifetime Financing setting.

The key input into XENDEE's Equipment Lifetime Financing tab is the "Loan Interest Rate," which is essentially the interest rate at which money can be borrowed to pay for the required capital expenditures. This is a key input, as it impacts the optimized levels of investments in PV and storage as they relate to future cost savings. Based on industry experience, financial research and discussions with NELHA regarding its funding sources, this study utilized a Loan Interest Rate of 6%. It is recognized that in many instances, NELHA's effective cost of capital may be lower than 6%. However, given the potential financial magnitude of these investments, it appeared reasonable to utilize a more conservative 6% Loan Interest Rate that more closely aligns with the cost of capital in the financial markets. Nevertheless, where appropriate, sensitivity analyses have been performed to analyze the impact of a lower Loan Interest Rate on the optimized simulation results.

The results of each XENDEE simulation under the Equipment Lifetime Financing setting include a schedule of future cash flows (expenditures and future savings). In order to analyze the value of those cash flows HNEI manually evaluated them in Excel using various financial metrics including:

- Simple Payback Period – The amount of time it takes to recover the cost of investment without accounting for the time-value of money;

- Discounted Payback Period – The amount of time it takes for the initial cost of a project to equal the discounted value of expected cash flows;

- Net Present Value ("NPV") – The difference between the present discounted value of cash inflows and the present discounted value of cash outflows over a period of time. A positive NPV indicates that a project is financially "in the money"; and

- Internal Rate of Return ("IRR") – The annual rate of growth that an investment is expected to generate (in other words, the discount rate that makes the NPV of a project zero). An IRR higher than the discount rate indicates that a project is financially "in the money".

In line with well-established financial theory, the discount rate utilized for the discounted payback period and NPV analyses was 6%, which is identical to the Loan Interest Rate used in the XENDEE analyses.

3 NELHA Microgrid Designs

HNEI, in collaboration with NELHA, evaluated four potential locations for microgrids at the HOST Park. The locations were selected based on the four HELCO meters that currently serve the NELHA facilities within the HOST Park. These meters provided the load data needed to conduct the analysis of each potential microgrid. The four meters are located at the Park's: (1) Research Campus; (2) Farm Compound; (3) 55" Pump Station; and (4) Booster Pump Station (collectively "Microgrid Load Centers").

Each proposed microgrid architecture is designed to serve either the loads served by a single meter or the loads of two geographically proximate meters. The Research Campus and Farm Compound are situated near each other at the north end of the park. Likewise, the Booster Pump Station and 55" Pump Station are situated near each other at the south end of the park. As a result, HNEI has evaluated combined microgrids for both the (1) Research Campus/Farm Compound location, and (2) the Booster Pump Station/55" Pump Station location. It appears that a single microgrid serving both the north and south locations would not be cost-effective, due to their geographic separation and other technical constraints (e.g., the unique control devices being implemented for the ENCORED Project).

In recognition of potential cost constraints associated with BESSs, each configuration evaluated in this report generally consists of two permutations. The first permutation derives an optimized amount of PV generation in a situation where BESSs are not allowed to be utilized (i.e., the "PV-Only" cases). The second permutation derives an optimized amount of PV generation in a situation where BESSs are allowed to be utilized (i.e., the "PV+BESS" cases).

The proposed microgrid designs generally utilize existing distribution infrastructure within the HOST Park. However, based on input from NELHA, HNEI also evaluated designs at the Research Campus and Farm Compound that incorporate additional infrastructure upgrades (e.g., new transformers), which would add additional costs to the final microgrid design. Another consideration for a microgrid serving the Research Campus and/or Farm Compound is the availability of a large parcel of undeveloped land in a nearby area known as the "Boneyard." NELHA expressed interest in utilizing the Boneyard due to the administrative efficiencies that could be realized by installing all of the requisite additional PV generation in a single project/location. However, as discussed below, due to the high cost of electrically connecting the Boneyard to the Research Campus/Farm Compound, it would be substantially more economical to install the new PV generation on the Research Campus itself.

In order to clearly identify the various microgrid scenarios, the following naming conventions are used in this report. As shown in Table 9 below, capital letters "A" through "E" correspond to the locations or combinations of locations selected for the particular microgrid. In the case of the Research Campus and Farm Compound, numbers "1" and "2" correspond to PV installation sites prioritized by location (Boneyard) and optimum economics, respectively. Also, in the case of the Research Campus and Farm Compound, lower case letters "e" and "n" correspond to the use of existing and new transformers, respectively.

Table 9: Microgrid Scenario Naming Conventions

Microgrid Loads		Research Campus Site Prioritization	
A	Research Campus	**1**	Boneyard
B	Combined Research Campus/Farm Compound	**2**	Economically Prioritized
C	55" Pump Station	**Transformers**	
D	Booster Pump Station	**e**	Use Existing Transformer
E	Combined 55" Pump Station/Booster Pump Station	**n**	Use New HELCO Transformer

Thus, by way of example, Scenario "A.1.e" refers to a microgrid that "A" serves the Research Campus load, prioritizing "1" new PV generation at the Boneyard and "e" using the existing transformer. For ease of comparison, Table 10 below summarizes some of the key results generated from the 31 simulations that have been performed in connection with the 10 scenarios analyzed in this report.

Table 10: Key Simulation Results

Scenario	Simulation	Load	kW PV	kWh BESS	Microgrid RE%[11]	Microgrid Load Center RE%[12]	Capex ($000)	NPV ($000)	IRR%
A.1.e	1	Low	465	[redacted]	39	24	650	906	18.5
	2	Low	465	55	40	24	680	909	17.8
	3	Mid	465	[redacted]	34	22	650	967	19.2
	4	Mid	756	600	54	34	2,091	1,200	12
	5	High	725	[redacted]	45	29	1,662	1,160	12.8
	6	High	1,065	1,109	63	44	3,360	1,737	11.5
A.1.n	7	High	1,065	1,278	65	44	3,879	1,311	9.7
A.2.e	8	Low	465	[redacted]	40	24	650	907	18.5
	9	Low	465	0	40	24	650	907	18.5
	10	Mid	524	[redacted]	38	24	854	1,040	17
	11	Mid	647	367	46	30	1,505	1,291	14.3
	12	High	647	[redacted]	41	27	1,303	1,376	15.7
	13	High	647	175	42	28	1,399	1,425	15.6
B.1.e	14	Low	768	[redacted]	---	36	1,965	851	10.3
	15	Low	911	505	---	44	2,700	976	9.8
	16	Mid	863	[redacted]	---	37	2,269	1,015	10.4
	17	Mid	993	425	---	43	2,919	1,470	11
	18	High	929	[redacted]	---	38	2,480	1,218	10.8
	19	High	1,065	771	---	44	3,339	1,875	11.5
B.1.n	20	Mid	1,054	664	---	46	3,700	1,005	8.8
	21	High	1,065	771	---	44	3,794	1,420	9.7
B.2.e	22	Low	674	[redacted]	---	34	1,399	1,102	13.2
	23	Low	786	184	---	39	1,914	1,182	11.6
	24	Mid	797	[redacted]	---	35	1,849	1,235	12.2
	25	Mid	797	371	---	39	2,054	1,800	13
	26	High	797	[redacted]	---	33	1,849	1,277	12.4
	27	High	797	740	---	33	2,256	2,210	12.7
B.2.n	28	High	797	740	---	33	2,691	1,723	10.7
C	29	[redacted]	661	0	46	43	609	202	9.3
D	30	[redacted]	18	0	19	34	54	70	17.6
E	31	[redacted]	711	0	---	45	770	220	8.9

[11] The microgrid renewable energy percentage ("Microgrid RE%") value is somewhat misleading in that the denominator is dependent upon the load of each optimized case. Therefore, a higher RE% does not necessarily indicate that one case provides more renewable energy than another. For example, Simulation 23 above yields a RE% of 39 based on a 786 kW PV/184 kWh BESS microgrid, while Simulation 27 yields a lower RE% of 33 based on a larger 797 kW PV/740 kWh BESS (which utilizes significantly more renewable energy than Simulation 23).

[12] In order to better reflect the overall amount of renewable energy enabled by the HOST Park microgrids, the "Microgrid Load Center RE%" value reflects the percentage of renewable energy utilized at two combined load centers: (1) the Research Campus/Farm Compound microgrid; and (2) the 55" Pump Station/Booster Pump Station microgrid. That is, the denominator for the A and B Scenarios is the total annual kWh consumed at the Research Campus and Farm Compound; and the denominator for Scenarios C, D and E is the total annual kWh consumed at the 55" Pump Station and Booster Pump Station. For Scenarios B and E, the Microgrid RE% and Microgrid Load Center RE% values are identical because the loads of the optimized cases already reflect the combined loads.

3.1 Scenario A.1.e (Research Campus, Boneyard, Existing Transformer)

3.1.1 Scenario A.1.e Description

Scenario A.1.e and its schematic at the point of connection ("PoC") are illustrated in Figure 5 below. This scenario represents a microgrid to serve only the Research Campus load, utilizing new PV generation from the Boneyard (prioritized ahead of the PV Test Bed, Power Building roof, Covered Parking Area, Ops Building roof, NELHA WQL roof and Pipeline Area locations) and the existing transformer. As noted in Section 2 above, the Research Campus already has 205 kW of existing PV generation. It is also assumed that as a result of its relatively lower cost, up to 260 kW of new PV generation is prioritized at the Innovation Village ahead of any PV installations at the Boneyard.

The key considerations for this scenario are: (1) the cost to electrically connect the Boneyard to the Research Campus; and (2) the future energy consumption of the Hydrogen Station. The cost to connect a PV system at the Boneyard to the Research Campus switchgear is estimated to be $180,000 (including a 10% contingency).[13]

The Hydrogen Station is expected to be one of the largest consumers of electricity at the Research Campus. To manage the total cost of energy at the Research Campus, it is recommended that NELHA carefully consider the scheduling of hydrogen production at the Hydrogen Station to minimize the electric bill impact of this incremental load. Thus, it is assumed that the facility would be operated to produce hydrogen during the daytime, when solar energy resources are abundant. However, there is a high degree of uncertainty as to how much hydrogen the facility will actually produce once placed into service. As a result, the consumption of the Research Campus has been evaluated under three load scenarios: (1) low; (2) medium; and (3) high.

[13] See Appendix A.

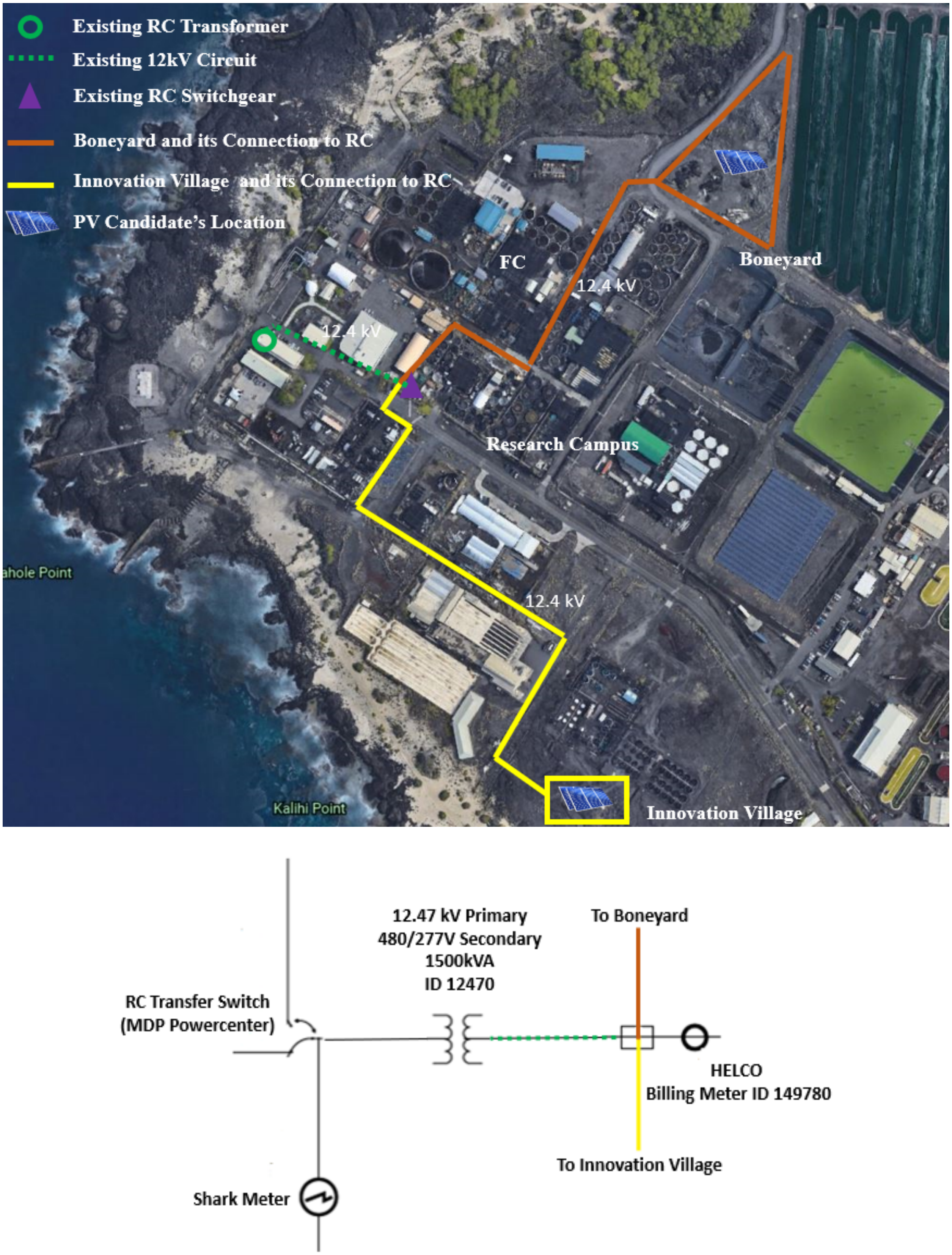


Figure 5: Scenario A.1.e and its Schematic at PoC

3.1.2 Scenario A.1.e Results

Simulation 1:

Load	**Research Campus**
Prioritized PV Location	**Boneyard**
Transformer	**Existing**
Technology	**PV-Only**
Hydrogen Production	**Low**
Discount Rate	**6%**

Results:

Location (Max kW)		Existing (205)	Innovation Village (260)	Boneyard (600)	Cum Total Fixed Cost ($)	Cum Total Capex ($000s)	Cum Total kW	Microgrid RE%	Project Payback Period* (simple years, discounted years)
Variable ($/kW)		0	2,500	3,200					
Fixed ($)		0	0	180,000					
XENDEE Optimizations (Incremental kW)									
Increment	0	205	---	---	0	0	205	15	---
	1	205	**260**	---	0	**650**	**465**	39	6, 7
	2	205	260	**0**	0	650	---	---	---
					Microgrid Load Center RE%:			**24**	
Cum Avg $/kW		---	2,500	---	Total Project Payback Period:				6, 7
Capex (in $000s)		---	650	---					
NPV (in $000s)		---	906	---	Total NPV (in $000s)				906
IRR (in %)		---	18.5	---	Total IRR (in %)				18.5
Increment		0	1	2					

* *Note: The Project Payback Period is for the incremental addition and is not cumulative.*

Simulation 1 Key Takeaways:

When energy consumption at the Research Campus is assumed to be at the low end of its range, an optimized PV-Only microgrid that prioritizes PV generation at the Boneyard (ahead of the PV Test Bed, WQL Roof and Pipeline Area locations) would incorporate all 260 kW of the PV generation potential at the Innovation Village, but none of the PV potential at the Boneyard due to its high fixed ($180,000) and variable ($3,200/kW) costs. The NPV of this microgrid is $906,000, which is the lowest of any Scenario A.1.e simulation; however, the 18.5% IRR indicates that adding PV at the Innovation Village would result in significant economic gains for the HOST Park.

The relatively small Microgrid Load Center RE% value of 24 reflects the fact that under the uncombined, low-load cases (see also Simulations 2, 8 and 9), there is a limited ability to utilize solar PV resources.

The economic viability of this case is significantly affected by the Loan Interest Rate assumption, due to its high costs. In this case, reducing the Loan Interest Rate from 6% to 0% results in a modest addition of 142 kW of PV from the Boneyard; however, the fixed cost of $180,000 would significantly degrade the value of the investment.

Simulation 2:

Load	**Research Campus**
Prioritized PV Location	**Boneyard**
Transformer	**Existing**
Technology	**PV+BESS**
Hydrogen Production	**Low**
Discount Rate	**6%**

Results:

Location (Max kW)		Existing (205)	Innovation Village (260)	Boneyard (600)	Cum Total Fixed Cost ($)	Cum Total Capex (PV + BESS) ($000s)	Cum Total kW	Microgrid RE%	Project Payback Period* (simple years, discounted years)
Variable ($/kW)		0	2,500	3,200					
Fixed ($)		0	0	180,000					
XENDEE Optimizations (Incremental kW, Total kWh)									
Increment	0	205, 0	---	---	0	0	205	15	---
	1	205, 0	**260, 55**	---	0	**680**	**465**	40	6, 7
	2	205, 0	260, 55	**0, 0**	0	---	---	---	---
					Microgrid Load Center RE%:			**24**	
Cum Avg $/kW		---	2,500	---	Total Project Payback Period:				6, 7
Capex PV ($000s)		---	680	---					
Capex BESS ($000s)		---	30						
NPV (in $000s)		---	922	---	Total NPV (in $000s)				909
IRR (in %)		---	18.4	---	Total IRR (in %)				17.8
Increment		0	1	2					

** Note: The Project Payback Period is for the incremental addition and is not cumulative.*

Simulation 2 Key Takeaways:

When the possibility of including a BESS is added to the assumptions for Simulation 1 above, the optimized solution adds a modest 55 kWh of battery storage to the microgrid. PV generation at the Boneyard continues to be infeasible, due to its high costs. The incremental cost of the BESS modestly reduces the IRR from 18.5% in Simulation 1 to 17.8% in this case.

However, the possibility of adding a BESS significantly supports the economic viability of adding PV generation from the Boneyard at lower Loan Interest Rates. In this case, reducing the Loan Interest Rate from 6% to 4% results in the addition of all 600 kW of available PV capacity from the Boneyard, along with a 2,350 kWh BESS.

In order to analyze the sensitivity of this case to the low-load assumption, HNEI considered a case where this microgrid was built out based on this optimized low-load sizing (i.e., 465 kW of PV and 55 a kWh BESS) but the actual future load ended up being at the high end of the range. The financial results of such a case are actually even stronger than the optimized solution, with an NPV of $962,000 and an IRR of 18.8%. In other words, this is a "no regrets" case provided that the actual future load falls somewhere within the assumed range.

Simulation 3:

Load	**Research Campus**
Prioritized PV Location	**Boneyard**
Transformer	**Existing**
Technology	**PV-Only**
Hydrogen Production	**Medium**
Discount Rate	**6%**

Results:

Location (Max kW)		Existing (205)	Innovation Village (260)	Boneyard (600)	Cum Total Fixed Cost ($)	Cum Total Capex ($000s)	Cum Total kW	Microgrid RE%	Project Payback Period* (simple years, discounted years)
Variable ($/kW)		0	2,500	3,200					
Fixed ($)		0	0	180,000					
XENDEE Optimizations (Incremental kW)									
Increment	0	205	---	---	0	0	205	15	---
	1	205	**260**	---	180,000	650	465	34	6, 7
	2	205	260	**0**	---	**---**	**---**	---	---
					Microgrid Load Center RE%:			**22**	
Cum Avg $/kW		---	2,500	---	Total Project Payback Period:				6, 7
Capex (in $000s)		---	650	---					
NPV (in $000s)		---	967	---	Total NPV (in $000s)				967
IRR (in %)		---	19.2	---	Total IRR (in %)				19.2
Increment		0	1	2					

* *Note: The Project Payback Period is for the incremental addition and is not cumulative.*

Simulation 3 Key Takeaways:

When energy consumption at the Research Campus under Simulation 1 above is increased from the low end to the middle of its range, the optimized PV-Only solution still does not add any PV generation from the Boneyard. The 19.2% IRR of this case is the highest of any simulation in this report. However, this case results in the lowest Microgrid RE% (34) and Microgrid Load Center RE% (22) of any of the Scenario A cases, as the inability to utilize PV generation from the Boneyard requires more energy from the HELCO grid to power the increase in hydrogen production.

It should be noted that the increase in load under this case supports the economic viability of adding PV generation from the Boneyard at lower Loan Interest Rates. In this case, reducing the Loan Interest Rate from 6% to 4% results in the addition of 177 kW of PV from the Boneyard (even without a BESS).

<u>Simulation 4</u>:

Load	**Research Campus**
Prioritized PV Location	**Boneyard**
Transformer	**Existing**
Technology	**PV+BESS**
Hydrogen Production	**Medium**
Discount Rate	**6%**

<u>Results</u>:

Location (Max kW)		Existing (205)	Innovation Village (260)	Boneyard (600)	Cum Total Fixed Cost ($)	Cum Total Capex (PV + BESS) ($000s)	Cum Total kW	Microgrid RE%	Project Payback Period* (simple years, discounted years)
Variable ($/kW)		0	2,500	3,200					
Fixed ($)		0	0	180,000					
XENDEE Optimizations (Incremental kW, Total kWh)									
Increment	0	205, 0	---	---	0	0	205	15	---
	1	205, 0	**260, 0**	---	0	650	465	34	6, 7
	2	205, 0	260, 0	**291, 600**	180,000	**2,091**	**756**	54	12, 18
					Microgrid Load Center RE%:			**34**	
Cum Avg $/kW		---	2,500	3,196	Total Project Payback Period:				8, 12
Capex PV ($000s)		---	650	1,111					
Capex BESS ($000s)		---	0	330					
NPV (in $000s)		---	967	234	Total NPV (in $000s)				1,200
IRR (in %)		---	19.2	7.9	Total IRR (in %)				12.0
Increment		0	1	2					

* *Note: The Project Payback Period is for the incremental addition and is not cumulative.*

Simulation 4 Key Takeaways:

When the possibility of including a BESS is added to the assumptions for Simulation 3 above, 291 kW of PV generation is added from the Boneyard, and the optimized amount of storage for the overall system is increased to 600 kWh (compared to 55 kWh under the low load case in Simulation 2).

This is the first case in which the optimized results actually include generation from the Boneyard. The additional fixed costs of doing so substantially diminish the value of the investment, however, as the IRR decreases from a high of 19.2% under Simulation 3 to 12.0% in this case.

Simulation 5:

Load	**Research Campus**
Prioritized PV Location	**Boneyard**
Transformer	**Existing**
Technology	**PV-Only**
Hydrogen Production	**High**
Discount Rate	**6%**

Results:

Location (Max kW)		Existing (205)	Innovation Village (260)	Boneyard (600)	Cum Total Fixed Cost ($)	Cum Total Capex ($000s)	Cum Total kW	Microgrid RE%	Project Payback Period* (simple years, discounted years)
Variable ($/kW)		0	2,500	3,200					
Fixed ($)		0	0	180,000					
XENDEE Optimizations (Incremental kW)									
Increment	0	205	---	---	0	0	205	13	---
	1	205	**260**	---	0	650	465	30	5, 7
	2	205	260	**260**	180,000	**1,662**	**725**	45	10, 15
					Microgrid Load Center RE%:			**29**	
Cum Avg $/kW		---	2,500	3,196	Total Project Payback Period:				8, 11
Capex (in $000s)		---	650	1,012					
NPV (in $000s)		---	978	331	Total NPV (in $000s)				1,160
IRR (in %)		---	19.3	9.3	Total IRR (in %)				12.8
Increment		0	1	2					

** Note: The Project Payback Period is for the incremental addition and is not cumulative.*

Simulation 5 Key Takeaways:

As shown in Figure 6 below, when energy consumption at the Research Campus under Simulation 3 above is increased from the middle to the high end of its range, the optimized PV-Only solution adds 260 kW of PV generation at the Boneyard. However, the incremental cost of the generation from the Boneyard is significantly higher than the cost of the Innovation Village increment.

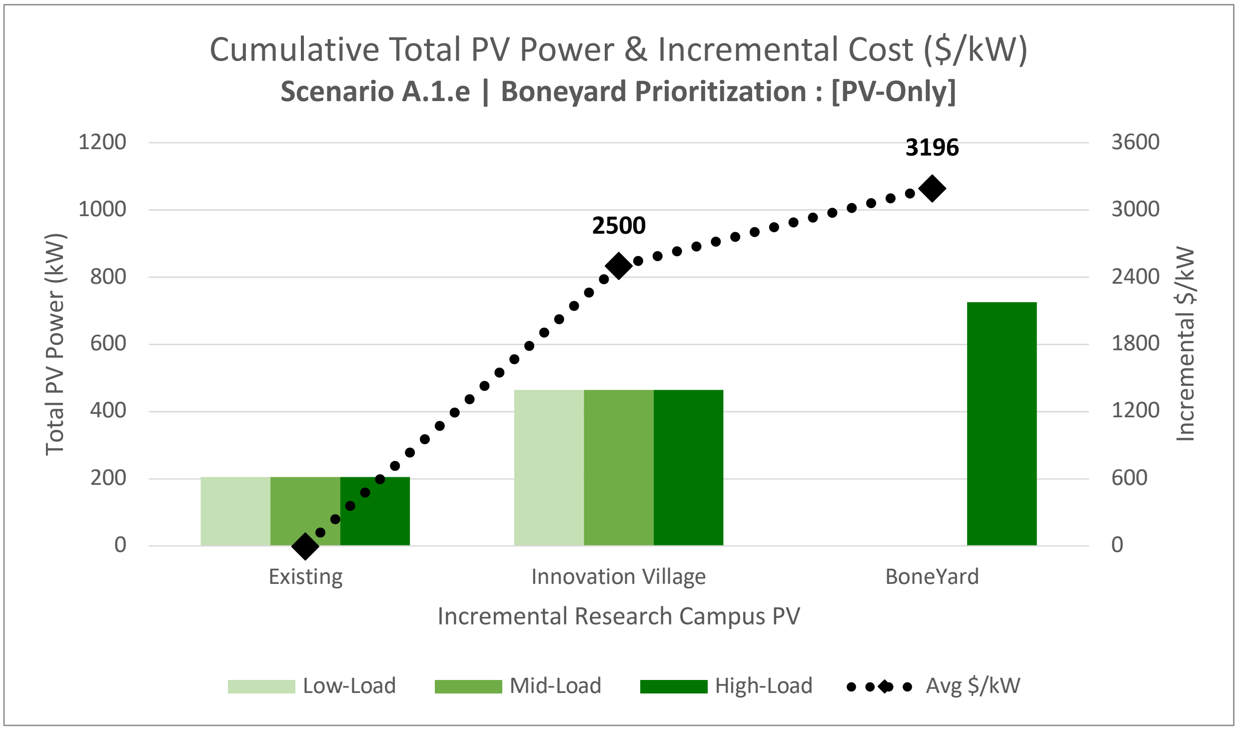


Figure 6: Impact of Scenario A.1.e PV-Only Increments

In comparison to Simulation 4 above, the reduced capex as a result of not including a BESS in this case results in a modest improvement in IRR from 12.0% to 12.8%.

Simulation 6:

Load	**Research Campus**
Prioritized PV Location	**Boneyard**
Transformer	**Existing**
Technology	**PV+BESS**
Hydrogen Production	**High**
Discount Rate	**6%**

Results:

Location (Max kW)		Existing (205)	Innovation Village (260)	Boneyard (600)	Cum Total Fixed Cost ($)	Cum Total Capex (PV + BESS) ($000s)	Cum Total kW	Microgrid RE%	Project Payback Period* (simple years, discounted years)
Variable ($/kW)		0	2,500	3,200					
Fixed ($)		0	0	180,000					
XENDEE Optimizations (Incremental kW, Total kWh)									
Increment	0	205, 0	---	---	0	0	205	13	---
	1	205, 0	**260, 0**	---	0	650	465	30	5, 7
	2	205, 0	260, 0	**600, 1,109**	180,000	**3,360**	**1,065**	63	9, 15
					Microgrid Load Center RE%:			**44**	
Cum Avg $/kW		---	2,500	3,197	Total Project Payback Period:				8, 12
Capex PV ($000s)		---	650	2,100					
Capex BESS ($000s)		---	0	610					
NPV (in $000s)		---	978	759	Total NPV (in $000s)				1,737
IRR (in %)		---	19.3	9.2	Total IRR (in %)				11.5
Increment		0	1	2					

** Note: The Project Payback Period is for the incremental addition and is not cumulative.*

Simulation 6 Key Takeaways:

When the possibility of including a BESS is added to the assumptions for Simulation 5 above, PV generation from the Boneyard increases from 260 kW to 600 kW, and the optimized amount of storage for the overall system increases from 600 kWh (under the medium load case in Simulation 4) to 1,109 kWh. However, of all of the simulations for Scenario A.1.e, this case requires the highest capex ($3.36 million) and yields the lowest IRR (11.5%). On the other hand, this case also yields the highest Microgrid RE% (63) and Microgrid Load Center RE% (44) of any Scenario A.1.e case. The size and $/kW impact of each Scenario A.1.e increment under the PV+BESS case are shown in Figure 7 below. Once again, for the Low Load case, PV generation at the Boneyard continues to be infeasible, due to its high upfront fixed costs of development.

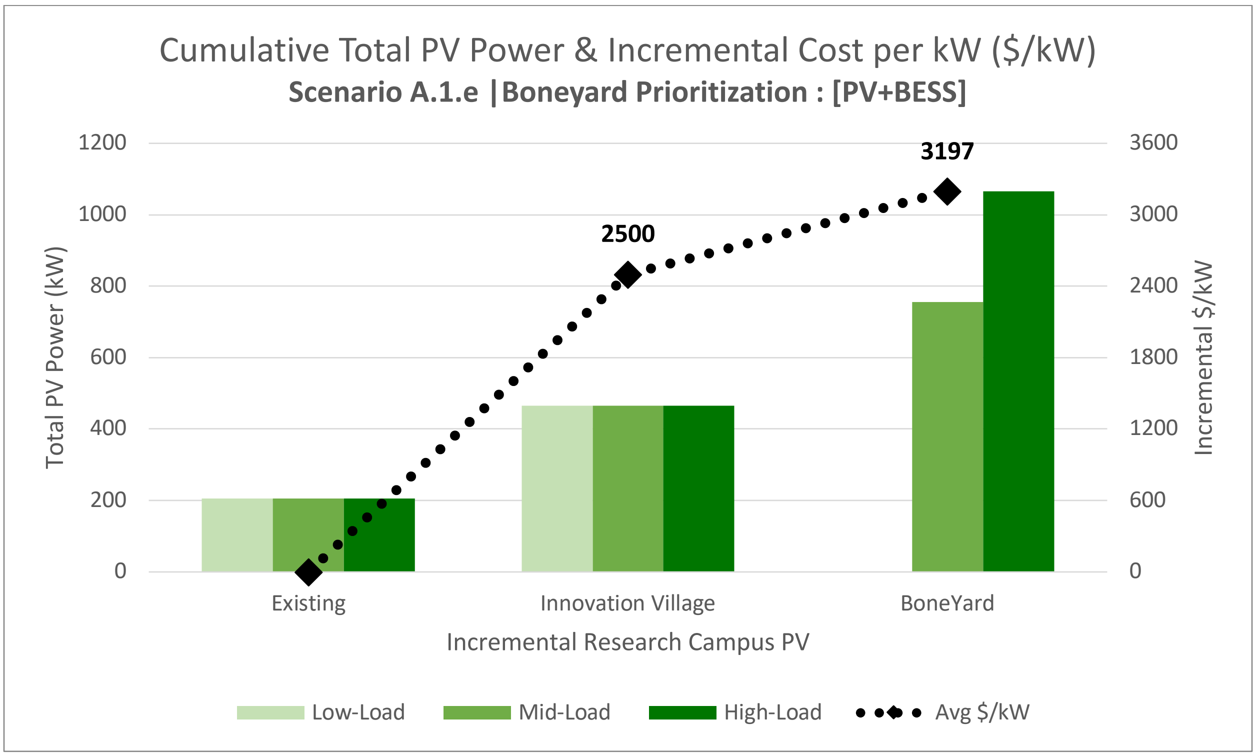


Figure 7: Impact of Scenario A.1.e PV+BESS Increments

In order to analyze the sensitivity of this case to the high-load assumption, HNEI considered a case where this microgrid was built out based on this optimized high-load sizing (i.e., 1,065 kW of PV and a 1,109 kWh BESS) but the actual future load ended up being at the low end of the range. The financial results of such a case are not as strong as the optimized solution, but still positive with an NPV of $186,000 and an IRR of 8.8%. In other words, this is a “no regrets” case provided that the actual future load falls within the assumed range.

3.1.3 Scenario A.1.e Conclusion

The high fixed cost of electrically connecting PV generation at the Boneyard to the Research Campus load renders Scenario A.1.e economically less optimal under the low energy consumption cases. Increasing Research Campus energy consumption to medium and high levels results in the addition of increased PV generation at the Boneyard (under a PV+BESS Scenario). As shown in Figure 8 below, the ability to accommodate PV generation at the Boneyard is enhanced when paired with energy storage, particularly at higher loads.

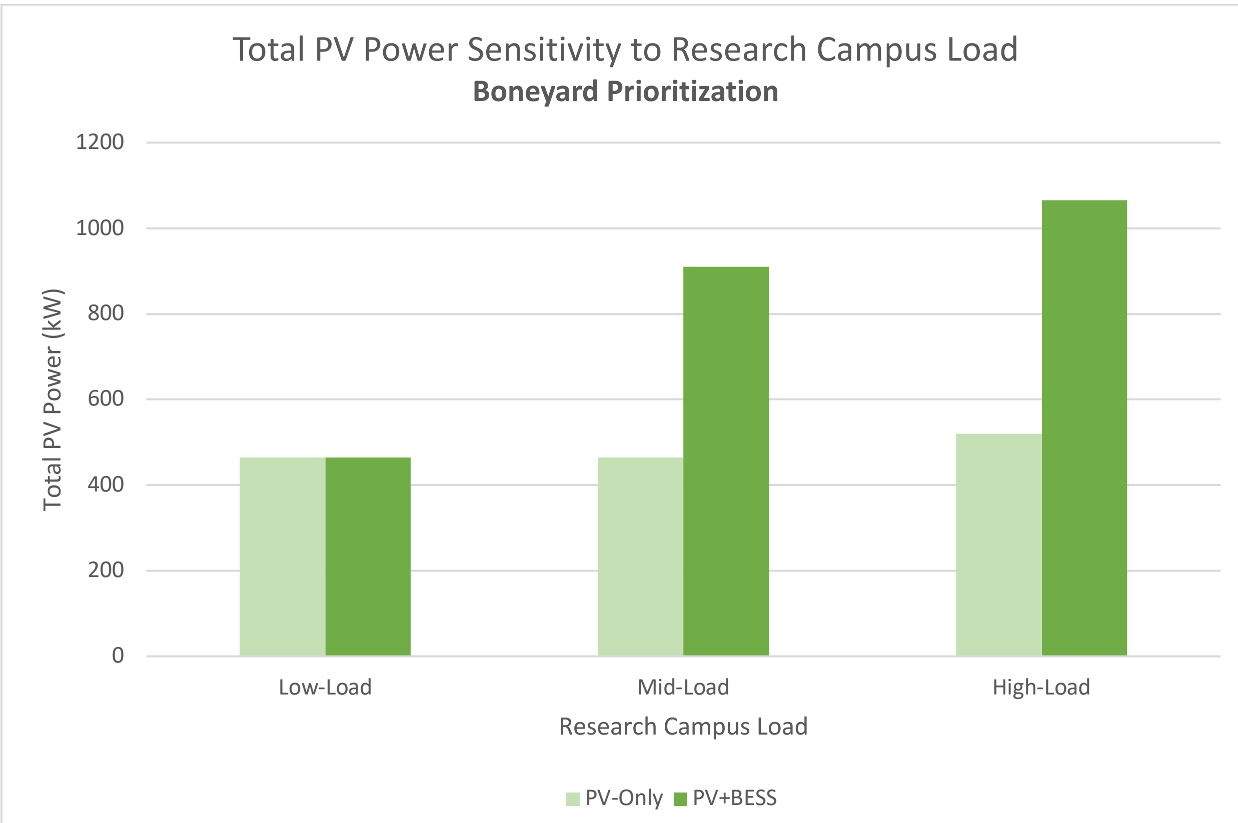


Figure 8: Scenario A.1.e Sensitivity of PV Sizing to Research Campus Load

As shown in Figure 9 below, all of the simulations under Scenario A.1.e result in positive NPVs. The NPVs increase as the load increases and are higher in the PV+BESS cases than in the PV-Only cases.

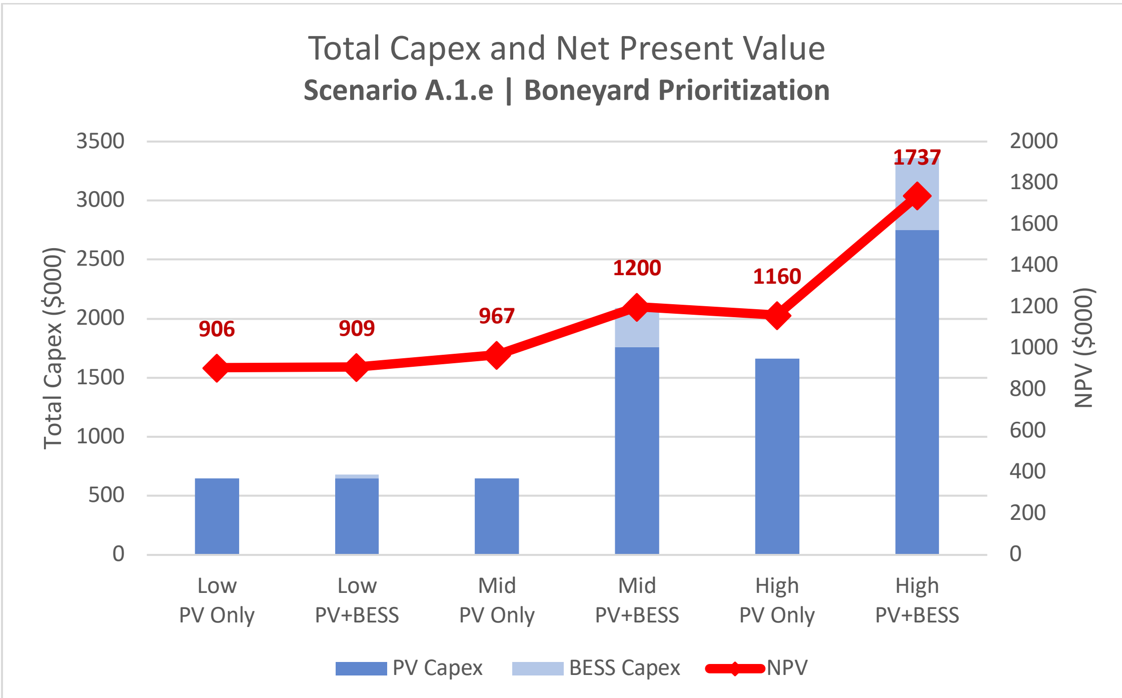


Figure 9: Scenario A.1.e Capex and NPVs

Reducing the Loan Interest Rate can result in the addition of PV from the Boneyard in cases where it would not otherwise be included in the optimized XENDEE solution. However, as shown in Figure 10 below, all cases in which PV generation is actually added to the Boneyard result in significantly lower IRRs, due to the higher incremental fixed cost.

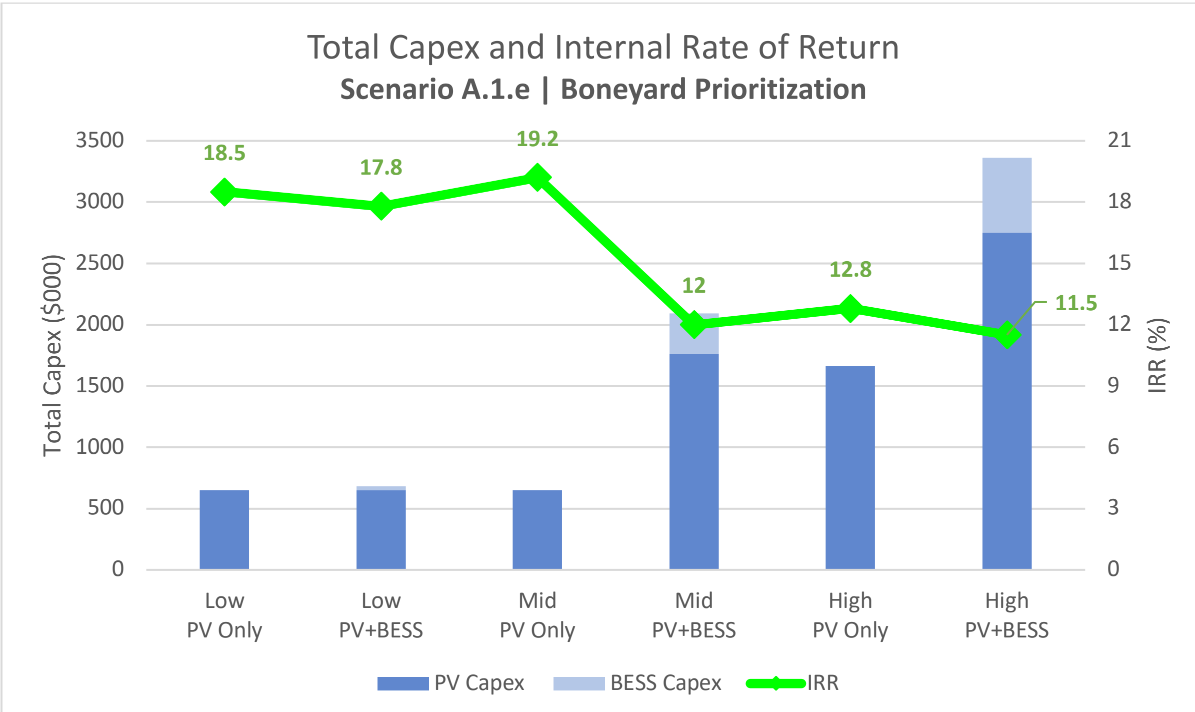


Figure 10: Scenario A.1.e Capex and IRRs

Assuming that NELHA proceeds with a PV+BESS microgrid under this scenario, the NPVs of the cases analyzed will be positive regardless of whether the actual load ends up being in the low, middle or high end of the assumed range. If NELHA builds out its microgrid based on the low-load assumption and the actual load is at the high end of the range, the financial results generally improve. Conversely if the microgrid is built out based on the high-load assumption and the actual load is at the low end of the range, the financial results are not as strong, but still positive, representing a “no regrets” solution as long as the actual loads are in the assumed range.

3.2 Scenario A.1.n (Research Campus, Boneyard, New Transformer)

3.2.1 Scenario A.1.n Description

As illustrated in Figure 11 below, Scenario A.1.n represents a microgrid to serve only the Research Campus load, utilizing new PV generation from the Boneyard (prioritized ahead of the PV Test Bed, Power Building roof, Covered Parking Area, Ops Building roof, NELHA WQL roof and Pipeline Area locations) and a new HELCO transformer. The fundamental difference between Scenario A.1.e above and this Scenario A.1.n is the use of a new HELCO transformer instead of the existing transformer.

The impetus for analyzing a scenario with a new transformer is based on NELHA's stated concern that if the existing transformer were to fail, there could be a significant lead time before a replacement transformer could be received on site. With the purchase and installation of the new transformer, the existing transformer could be held in reserve as a back-up if the new transformer were to fail, which provides added resiliency to the microgrid.

The new transformer increases the estimated fixed cost of the Research Campus microgrid by \$426,000 from \$180,000 under Scenario A.1.e to \$606,000 under Scenario A.1.n.[14] The increase is attributable to costs to replace the transformer and related conductors. Due to these increased fixed costs, the only load scenario under which Scenario A.1.n is shown to be economically feasible in XENDEE is the high-load PV+BESS case. (None of the other cases result in the addition of any new PV or storage; therefore, the results below only reflect the high-load PV+BESS case.)

[14] See Appendix B.

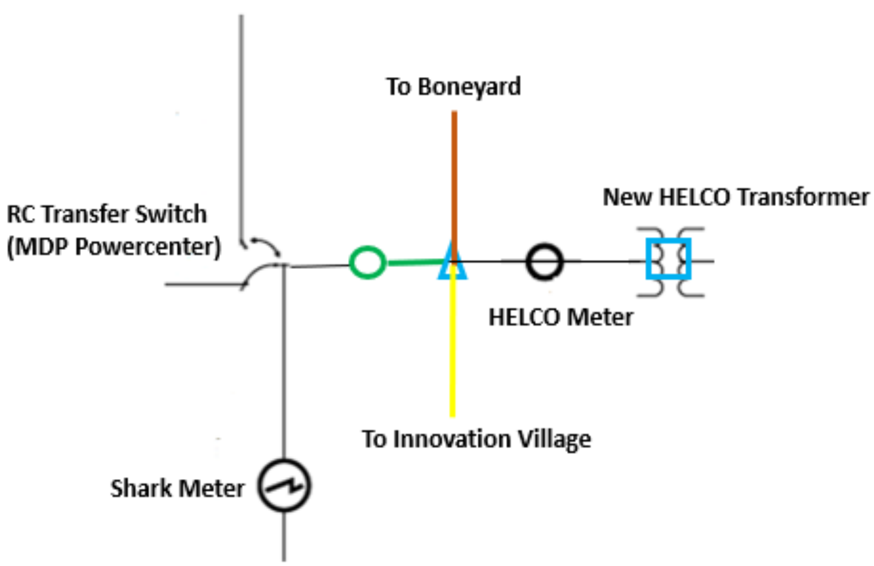


Figure 11: Scenario A.1.n and its Schematic at PoC

3.2.2 Scenario A.1.n Results

Simulation 7:

Load	**Research Campus**
Prioritized PV Location	**Boneyard**
Transformer	**New**
Technology	**PV+BESS**
Hydrogen Production	**High**
Discount Rate	**6%**

Results:

Location (Max kW)		Existing (205)	Innovation Village (260)	Boneyard (600)	Cum Total Fixed Cost ($)	Cum Total Capex (PV + BESS) ($000s)	Cum Total kW	Microgrid RE%	Project Payback Period* (simple years, discounted years)
Variable ($/kW)		0	2,500	3,200					
Fixed ($)		0	0	606,000					
XENDEE Optimizations (Incremental kW, Total kWh)									
Increment	0	205, 0	---	---	0		205	13	---
	1	205, 0	**260, 0**	---	0	650	465	30	6, 7
	2	205, 0	260, 0	**600, 1,278**	**606,000**	**3,879**	**1,065**	65	12, 19
					Microgrid Load Center RE%:			**44**	
Cum Avg $/kW		---	2,500	3,693	Total Project Payback Period:				9, 14
Capex PV ($000s)		---	650	2,526					
Capex BESS ($000s)		---	0	703					
NPV (in $000s)		---	978	333	Total NPV (in $000s)				1,311
IRR (in %)		---	19.3	7.2	Total IRR (in %)				9.7
Increment		0	1	2					

* Note: The Project Payback Period is for the incremental addition and is not cumulative.

3.2.3 Scenario A.1.n Conclusion

The cost of adding a new HELCO transformer increases the fixed cost of Scenario A.1.n by more than three-fold, to $606,000, significantly hindering the economics of this scenario. The increased fixed cost renders all of the simulations under Scenario A.1.n economically infeasible in XENDEE except for the high energy consumption PV+BESS case. The $3.9 million capex cost under this case is higher than any other case that includes the Research Campus, and the 9.7% IRR under this case is lower than any case in Scenario A.1.e (although still significantly higher than the assumed Loan Interest Rate of 6%).

From a purely financial perspective, adding a new transformer reduces the financial value of this case. However, from a business standpoint, the added resiliency that results from utilizing a new transformer (and saving the existing transformer as a backup) may justify the additional investment. Nonetheless, as discussed below, other potential PV sites within the Research Campus offer more financially viable alternatives than the Boneyard.

3.3 Scenario A.2.e (Research Campus, Economically Prioritized, Existing Transformer)

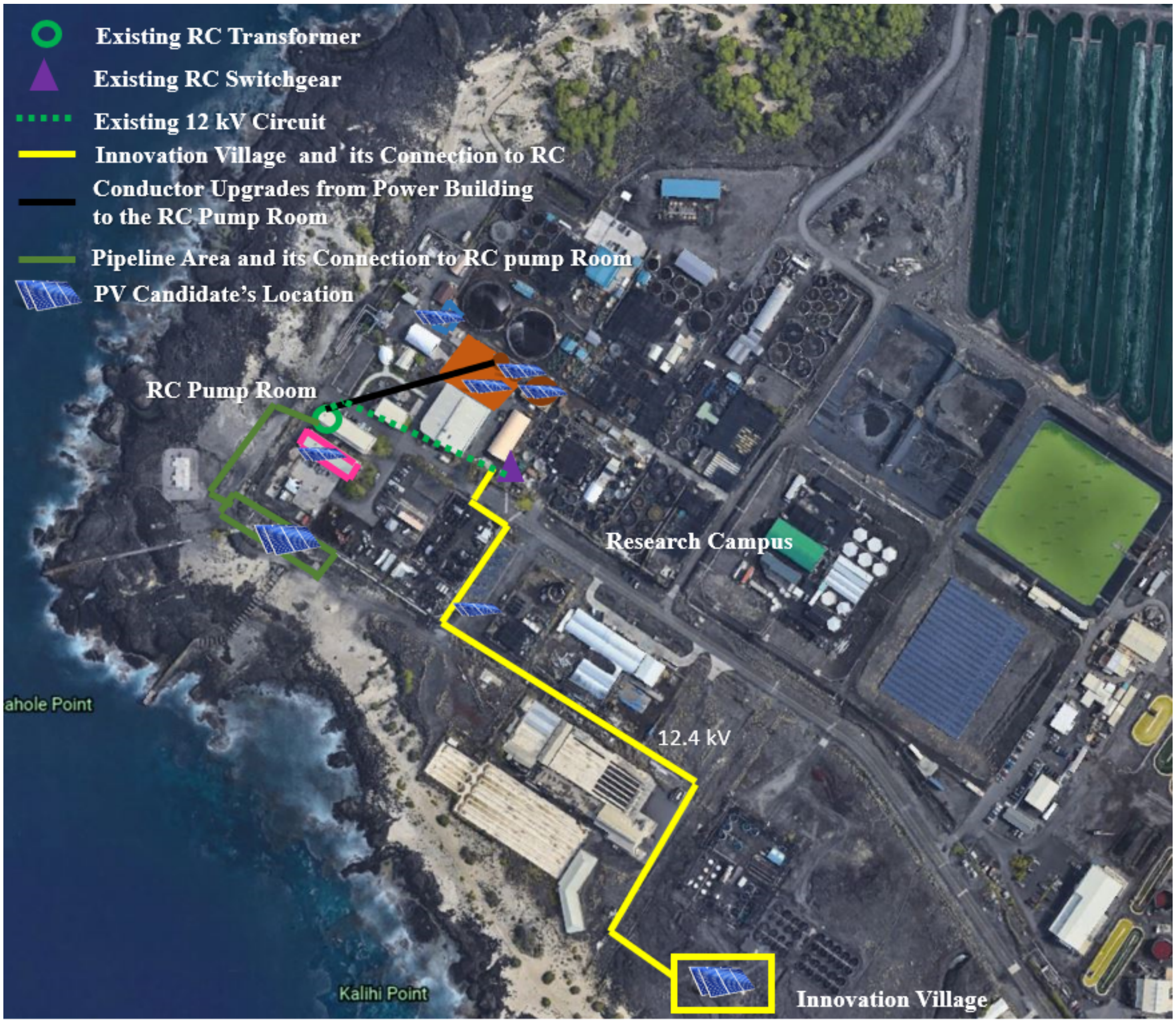
3.3.1 Scenario A.2.e Description

As illustrated in Figure 12 below, Scenario A.2.e represents a microgrid to serve only the Research Campus load, utilizing new PV generation from the Innovation Village and various sites within the Research Campus, and the existing transformer. As noted in Section 2 above, the Research Campus already has 205 kW of existing PV generation. Under this scenario, additional increments of PV generation are economically prioritized based on their all-in average $/kW cost. First priority is given to the Innovation Village, as the fixed cost of electrically connecting it to the Research Campus is considered a "sunk cost" and therefore treated as zero. Additional increments are economically prioritized in the following order, based on their variable and fixed costs (if any): (1) PV Test Bed; (2) NELHA WQL roof; (3) Pipeline Area; (4) Power Building roof; (5) Ops Building roof; (6) Covered Parking Area; and (7) Boneyard. However, none of the simulations resulted in the need for PV generation beyond the Pipeline Area.

Similar to the Scenario A.1 cases that prioritized PV generation at the Boneyard, the future energy consumption of the new Hydrogen Station is a key consideration affecting the economics of this microgrid configuration, and the Research Campus energy consumption has therefore been evaluated under three load scenarios: (1) low; (2) medium; and (3) high.

While the fixed costs are lower under this Scenario A.2.e than under Scenario A.1.e above, conductors connecting the Power Building to the transformer located in the Research Campus Pump Room will need to be upgraded (represented by a black connection line in Figure 12 below). According to NELHA personnel, this upgrade is estimated to cost approximately $100,000 (fixed cost) as reflected in the cases below.[15]

[15] See Appendix C.



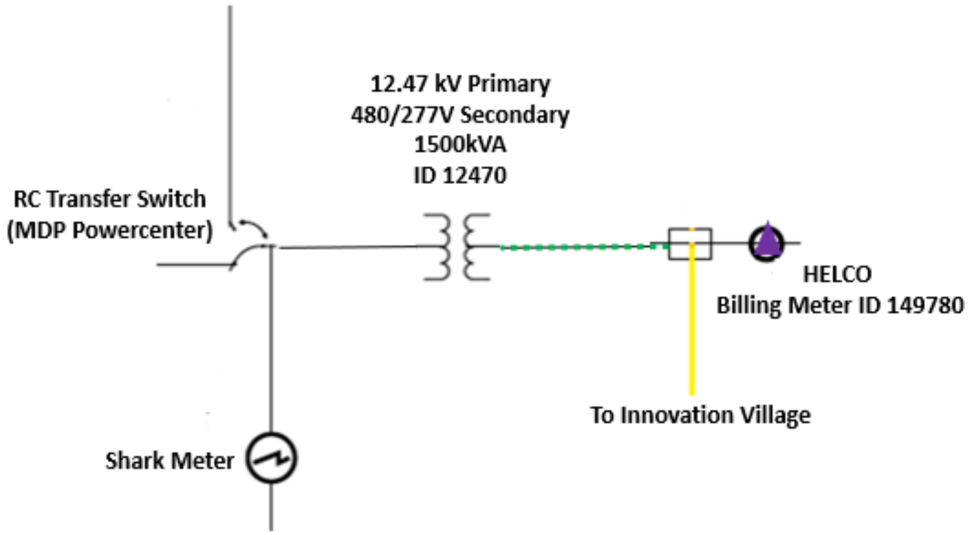


Figure 12: Scenario A.2.e and its Schematic at PoC

3.3.2 Scenario A.2.e Results

Simulation 8:

Load	**Research Campus**
PV Location Prioritization	**By Average $/kW**
Transformer	**Existing**
Technology	**PV-Only**
Hydrogen Production	**Low**
Discount Rate	**6%**

Results:

Location (Max kW)		Existing (205)	Innovation Village (260)	PV Test Bed (8)	Cum Total Fixed Cost ($)	Cum Total Capex ($000s)	Cum Total kW	Microgrid RE%	Project Payback Period* (simple years, discounted years)
Variable ($/kW)		0	2,500	3,000					
Fixed ($)		0	0	0					
XENDEE Optimizations (Incremental kW)									
Increment	0	205	---	---	0	0	205	15	---
	1	205	**260**	---	0	**650**	465	40	6, 7
	2	205	260	**0**	0	---	---	---	---
					Microgrid Load Center RE%:			**24**	
Cum Avg $/kW		---	2,500	---	Total Project Payback Period:				6, 7
Capex (in $000s)		---	650	---					
NPV (in $000s)		---	907	---	Total NPV (in $000s)				907
IRR (in %)		---	18.5	---	Total IRR (in %)				18.5
Increment		0	1	2					

* Note: The Project Payback Period is for the incremental addition and is not cumulative.

Simulation 8 Key Takeaways:

When potential PV installations at the Research Campus are prioritized in order of lowest all-in average variable costs, under the low-load PV-Only scenario, XENDEE selects all of the solar potential from the Innovation Village but stops short of adding any generation from the PV Test Bed. This case does not incur any fixed costs, and therefore results in relatively low capex ($650,000) and a correspondingly high IRR (18.5%).

Simulation 9:

Load	**Research Campus**
PV Location Prioritization	**By Average $/kW**
Transformer	**Existing**
Technology	**PV+BESS**
Hydrogen Production	**Low**
Discount Rate	**6%**

Results:

Location (Max kW)		Existing (205)	Innovation Village (260)	PV Test Bed (8)	Cum Total Fixed Cost ($)	Cum Total Capex (PV + BESS) ($000s)	Cum Total kW	Microgrid RE%	Project Payback Period* (simple years, discounted years)
Variable ($/kW)		0	2,500	3,000					
Fixed ($)		0	0	0					
XENDEE Optimizations (Incremental kW, Total kWh)									
Increment	0	205, 0	---	---	0	0	205	15	---
	1	205, 0	**260, 0**	---	0	**650**	465	40	6, 7
	2	205, 0	260, 0	**0, 0**	0	---	---	---	---
					Microgrid Load Center RE%:			**24**	
Cum Avg $/kW		---	2,500	---	Total Project Payback Period:				6, 7
Capex PV ($000s)		---	650	---					
Capex BESS ($000s)		---	0	---					
NPV (in $000s)		---	907	---	Total NPV (in $000s)				907
IRR (in %)		---	18.5	---	Total IRR (in %)				18.5
Increment		0	1	2					

** Note: The Project Payback Period is for the incremental addition and is not cumulative.*

Simulation 9 Key Takeaways:

Adding the possibility of including a BESS to the assumptions for Simulation 8 above does not result in the actual addition of any storage; therefore, the results in this case are identical to the results of Simulation 8.

In order to analyze the sensitivity of this case to the low-load assumption, HNEI considered a case where this microgrid was built out based on this optimized low-load sizing (i.e., 465 kW of PV and no BESS) but the actual future load ended up being at the high end of the range. The financial results of such a case are even stronger than the optimized solution, with an NPV of $990,000 and an IRR of 20.4%. In other words, this is a "no regrets" case provided that the actual future load falls within the assumed range.

Simulation 10:

Load	**Research Campus**
PV Location Prioritization	**By Average $/kW**
Transformer	**Existing**
Technology	**PV-Only**
Hydrogen Production	**Medium**
Discount Rate	**6%**

Results:

Location (Max kW)		Existing (205)	Innovation Village (260)	PV Test Bed (8)	WQL Roof (51)	Pipeline Area (123)	Cum Total Fixed Cost ($)	Cum Total Capex ($000s)	Cum Total kW	Micro grid RE%	Project Payback Period* (simple years, discounted years)
Variable ($/kW)		0	2,500	3,000	2,500	3,200					
Fixed ($)		0	0	0	52,000	55,000					
XENDEE Optimizations (Incremental kW)											
Increment	0	205	---	---	---	---	0	0	205	14.5	---
	1	205	**260**	---	---	---	0	650	465	34	6, 7
	2	205	260	**8**	---	---	0	674	473	34	24, 25+
	3	205	260	8	**51**	---	**52,000**	**854**	**524**	38	9, 13
	4	205	260	8	51	**0**	---	---	---	---	---
							Microgrid Load Center RE%: **24**				
Cum Avg $/kW		---	2,500	2,515	2,675	---	Total Project Payback Period:				6, 8
Capex ($000s)		---	650	24	180	---					
NPV (in $000s)		---	967	(10)	83	---	Total NPV (in $000s)				1,040
IRR (in %)		---	19.2	0.7	10.5	---	Total IRR (in %)				17.0
Increment		0	1	2	3	4					

** Note: The Project Payback Period is for the incremental addition and is not cumulative.*

Simulation 10 Key Takeaways:

Under a PV-Only case, increasing energy consumption at the Research Campus from low to medium results in the addition of all of the available PV from the WQL Roof (51 kW), but none from the Pipeline Area. The fixed cost of installing PV at the WQL Roof ($52,000) causes a marginal decrease in IRR (to 17%) when compared to the low-load scenarios in Simulations 8 and 9.

The exclusion of the Pipeline Area from this optimized solution is affected by the assumed Loan Interest Rate. Reducing the 6% Loan Interest Rate to 4%, 3% and 2%, results in Pipeline Area PV additions of 84 kW, 113 kW and 123 kW, respectively.

Simulation 11:

Load	**Research Campus**
PV Location Prioritization	**By Average $/kW**
Transformer	**Existing**
Technology	**PV+BESS**
Hydrogen Production	**Medium**
Discount Rate	**6%**

Results:

Location (Max kW)		Existing (205)	Innovation Village (260)	PV Test Bed (8)	WQL Roof (51)	Pipeline Area (123)	Cum Total Fixed Cost ($)	Cum Total Capex (PV + BESS) (in $000s)	Cum Total kW	Micro grid RE%	Project Payback Period* (simple years, discounted years)
Variable ($/kW)		0	2,500	3,000	2,500	3,200					
Fixed ($)		0	0	0	52,000	55,000					
XENDEE Optimizations (Incremental kW, Total kWh)											
Increment	0	205, 0	---	---	---	---	0	0	205	14.5	---
	1	205, 0	**260, 0**	---	---	---	0	650	465	34	5, 7
	2	205, 0	260, 0	**8, 24**	---	---	0	687	473	34	7, 9
	3	205, 0	260, 0	8, 0	**51, 116**	---	52,000	918	524	37	8, 11
	4	205, 0	260, 0	8, 0	51, 0	**123, 367**	107,000	**1,505**	**647**	46	9, 14
							Microgrid Load Center RE%: **30**				
Cum Avg $/kW		---	2,500	2,515	2,675	2,812	Total Project Payback Period:				7, 9
Capex PV ($000s)		---	650	24	180	449					
Capex BESS ($000s)		---	0	13	64	202					
NPV (in $000s)		---	967	22	114	188	Total NPV (in $000s)				1,291
IRR (in %)		---	19.2	12.9	11.2	9.4	Total IRR (in %)				14.3
Increment		0	1	2	3	4					

* *Note: The Project Payback Period is for the incremental addition and is not cumulative.*

Simulation 11 Key Takeaways:

When the possibility of including a BESS is added to the assumptions for Simulation 10 above, the optimized solution adds 367 kWh of storage to the microgrid. The BESS, in turn, enables the utilization of all 123 kW of available PV generation at the Pipeline Area (but stops short of adding any PV from the Power Building roof). The 14.3% IRR for this case is the lowest of any cases under Scenario A.2.e, but significantly higher than the 12% IRR when the Boneyard was prioritized under Simulation 4.

This case also results in the highest Microgrid RE% (46) and Microgrid Load Center RE% (30) of any case under Scenario A.2.e.

The exclusion of the Power Building roof from this optimized solution is affected by the assumed Loan Interest Rate. Reducing the Loan Interest Rate from 6% to 4% results in the addition of all of the PV capacity being added from the Power Building roof.

Simulation 12:

Load	**Research Campus**
PV Location Prioritization	**By Average $/kW**
Transformer	**Existing**
Technology	**PV-Only**
Hydrogen Production	**High**
Discount Rate	**6%**

Results:

Location (Max kW)		Existing (205)	Innovation Village (260)	PV Test Bed (8)	WQL Roof (51)	Pipeline Area (123)	Cum Total Fixed Cost ($)	Cum Total Capex ($000s)	Cum Total kW	Micro grid RE%	Project Payback Period* (simple years, discounted years)
Variable ($/kW)		0	2,500	3,000	2,500	3,200					
Fixed ($)		0	0	0	52,000	55,000					
XENDEE Optimizations (Incremental kW)											
Increment	0	205	---	---	---	---	0	0	205	13	---
	1	205	**260**	---	---	---	0	650	465	30	6, 7
	2	205	260	**8**	---	---	0	674	473	30	7 ,9
	3	205	260	8	**51**	---	52,000	854	524	33	8, 10
	4	205	260	8	51	**123**	**107,000**	**1,303**	**647**	41	9, 13
							Microgrid Load Center RE%: **27**				
Cum Avg $/kW		---	2,500	2,515	2,675	2,812	Total Project Payback Period:				7, 8
Capex ($000s)		---	650	24	180	449					
NPV (in $000s)		---	977	26	143	229	Total NPV (in $000s)				1,376
IRR (in %)		---	19.3	15.16	13.5	11	Total IRR (in %)				15.7
Increment		0	1	2	3	4					

* Note: The Project Payback Period is for the incremental addition and is not cumulative.

Simulation 12 Key Takeaways:

As shown in Figure 13 below, under a PV-Only case, increasing energy consumption at the Research Campus from medium to high results in the addition of all 123 kW of available PV generation at the Pipeline Area when compared to the medium load case in Simulation 10.

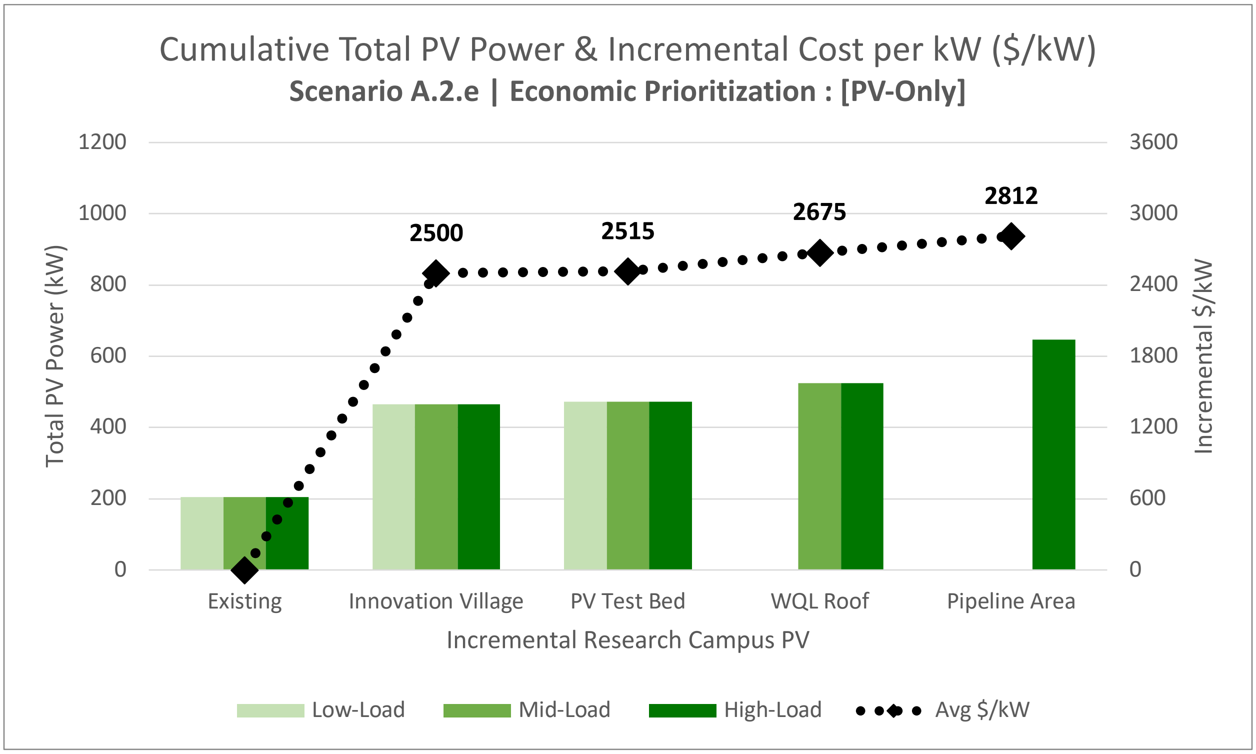


Figure 13: Impact of Scenario A.2.e PV-Only Increments

However, XENDEE stops short of adding any PV generation from the Power Building roof due to the high incremental fixed costs. Similar to the medium load case in Simulation 10, the 15.7% IRR under this case is higher than the 12.8% IRR when the Boneyard was prioritized in Simulation 5. Reducing the Loan Interest Rate from 6% to 4% results in the addition of all of the PV capacity being added from the Power Building roof.

Simulation 13:

Load	**Research Campus**
PV Location Prioritization	**By Average $/kW**
Transformer	**Existing**
Technology	**PV+BESS**
Hydrogen Production	**High**
Discount Rate	**6%**

Results:

Location (Max kW)		Existing (205)	Innovation Village (260)	PV Test Bed (8)	WQL Roof (51)	Pipeline Area (123)	Cum Total Fixed Cost ($)	Cum Total Capex (PV + BESS) (in $000s)	Cum Total kW	Micro grid RE%	Project Payback Period* (simple years, discounted years)
Variable ($/kW)		0	2,500	3,000	2,500	3,200					
Fixed ($)		0	0	0	52,000	55,000					
XENDEE Optimizations (Incremental kW, Total kWh)											
Increment	0	205, 0	---	---	---	---	0	0	205	13	---
	1	205, 0	**260, 0**	---	---	---	0	650	465	30	6, 7
	2	205, 0	260, 0	**8, 24**	---	---	0	674	473	30	7, 8
	3	205, 0	260, 0	8, 0	**51, 0**	---	52,000	854	524	33	8, 10
	4	205, 0	260, 0	8, 0	51, 0	**123, 175**	107,000	**1,399**	**647**	42	8, 12
							Microgrid Load Center RE%: **28**				
Cum Avg $/kW		---	2,500	2,515	2,675	2,812	Total Project Payback Period:				7, 8
Capex PV ($000s)		---	650	24	180	449					
Capex BESS ($000s)		---	0	0	0	96					
NPV (in $000s)		---	978	27	143	277	Total NPV (in $000s)				1,425
IRR (in %)		---	19.3	16.3	13.5	11.4	Total IRR (in %)				15.6
Increment		0	1	2	3	4					

* *Note: The Project Payback Period is for the incremental addition and is not cumulative.*

Simulation 13 Key Takeaways:

As shown in Figure 14 below, when the possibility of including a BESS is added to the assumptions for Simulation 12 above, the amount of PV generation remains unchanged.

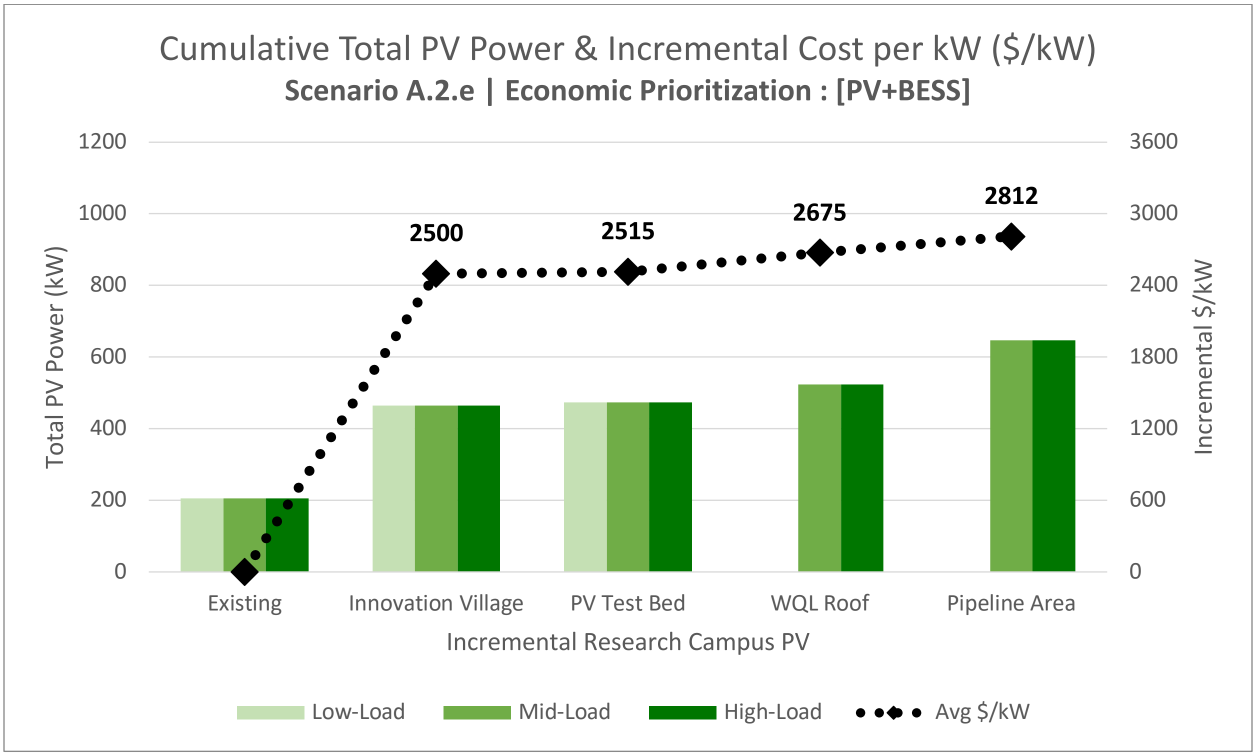


Figure 14: Impact of Scenario A.2.e PV+BESS Increments

However, as shown in Figure 15 below, the size of the PV system for the PV+BESS case is slightly smaller than under the medium energy consumption case in Simulation 11. Similar to when the Boneyard was prioritized in Simulation 6, this appears to be the result of more contemporaneous generation and consumption of PV resources.

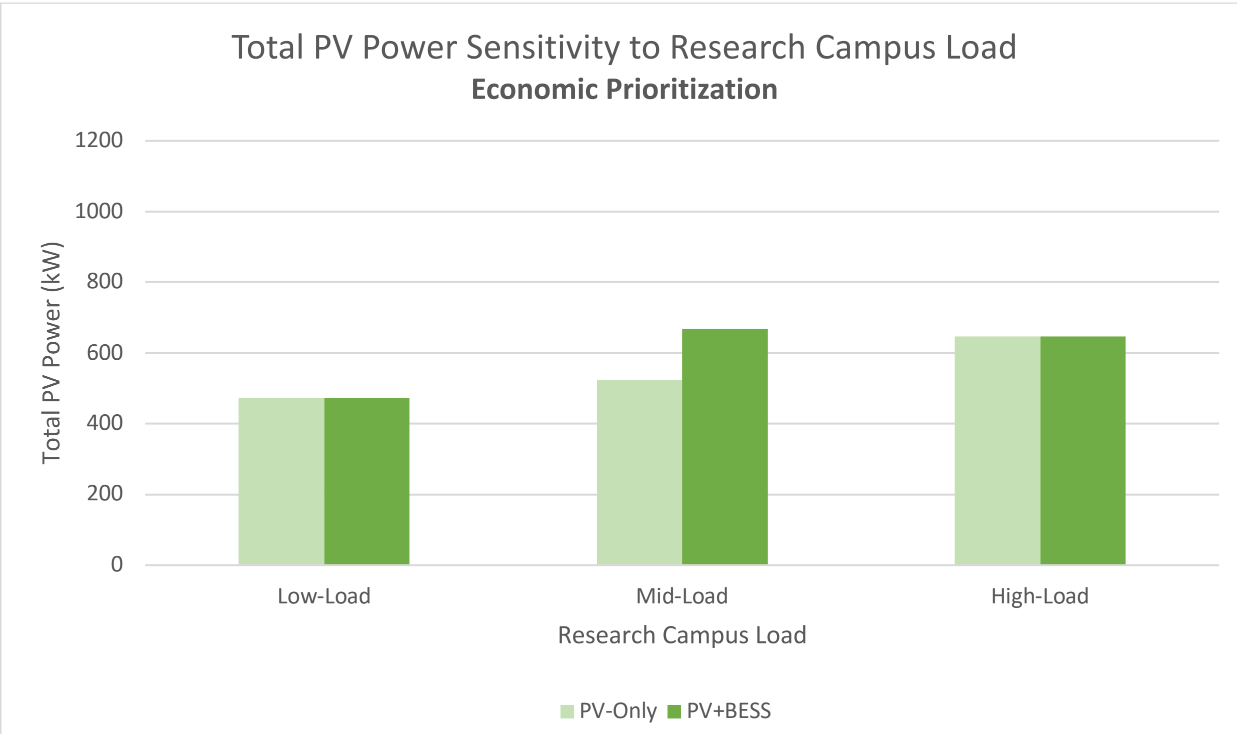


Figure 15: Scenario A.2.e Sensitivity of PV Sizing to Research Campus Load

When compared to the medium energy consumption case in Simulation 11, the smaller BESS under this scenario reduces capital costs by $106,000 from $1,505,000 in Simulation 11 to $1,399,000. The reduced capital costs result in this case having the highest NPV ($1.4 million) of any case in Scenario A.2.e. However, this high-load case has a modestly lower Microgrid RE% (42) and Microgrid Load Center RE% (28) than the mid-load case in Simulation 11, due to increased reliance on power from the HELCO grid to facilitate the higher level of hydrogen production.

The exclusion of the Power Building roof and the size of the battery for this optimized solution are both affected by the assumed Loan Interest Rate. When the Loan Interest Rate is reduced from 6% to 4%, additional PV is added from the Power Building roof and the optimized size of the battery roughly doubles in size.

In order to analyze the sensitivity of this case to the high-load assumption, HNEI considered a case where this microgrid was built out based on this optimized high-load sizing (i.e., 647 kW of PV and a 175 kWh BESS) but the actual future load ended up being at the low end of the range. The financial results of such a case are not as strong as the optimized solution, but still positive with an NPV of $674,000 and an IRR of 10.9%. In other words, this is a "no regrets" case provided that the actual future load falls within the assumed range.

3.3.3 Scenario A.2.e Conclusion

The relatively low fixed cost of installing PV generation at the PV Test Bed, WQL Roof and Pipeline Area result in Scenario A.2.e being much more economical than the cases where the Boneyard was prioritized in Scenario A.1.e. The NPVs and IRRs of the Scenario A.2.e simulations are shown below in Figure 16 and Figure 17, respectively. Of note, the mid-load PV+BESS case yields the lowest IRR, due to the relatively large size of the BESS.

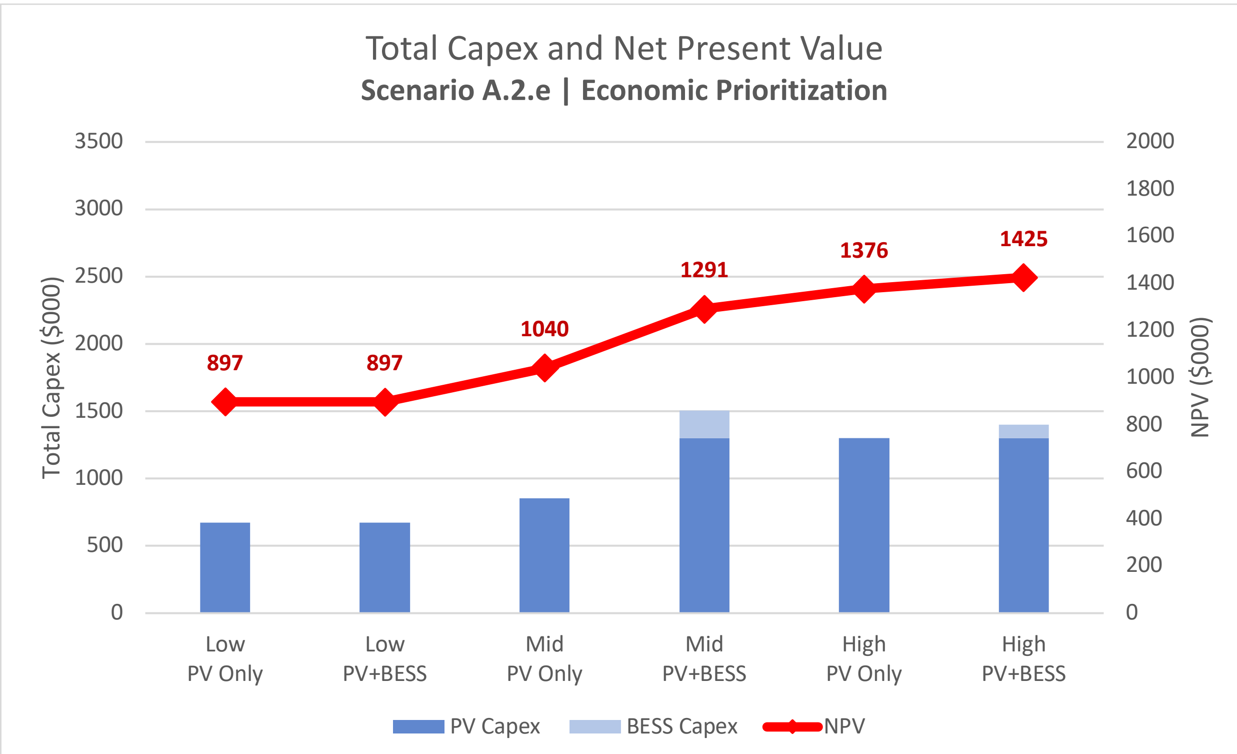


Figure 16: Scenario A.2.e Capex and NPVs

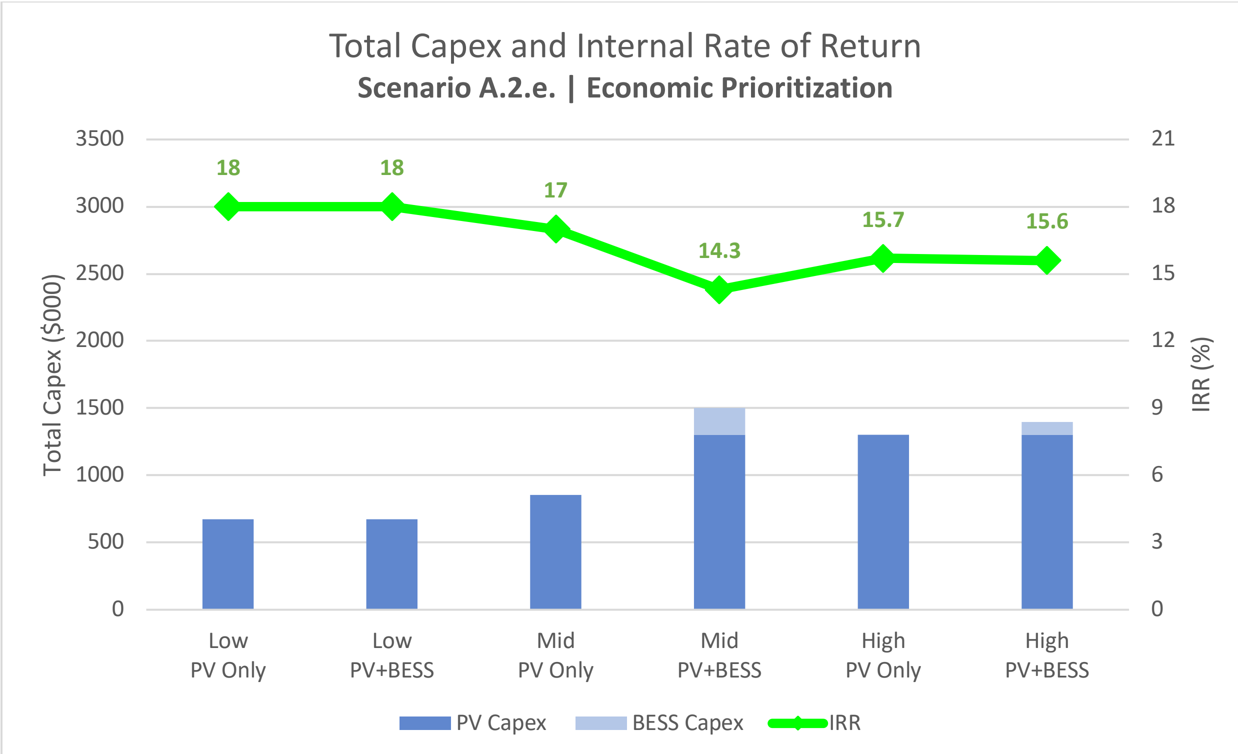


Figure 17: Scenario A.2.e Capex and IRRs

Similar to Scenario A.1.e, higher levels of energy consumption at the Research Campus support higher levels of PV generation, and the ability to accommodate PV generation is further enhanced when paired with energy storage. Reductions in the assumed Loan Interest Rate can result in this scenario adding additional PV from the Power Building roof and greater amounts of storage.

Every increment of PV generation under this scenario reduces operating costs. However, it should be noted that because each increment is prioritized based on all-in average $/kW costs (i.e., $/kW increases with each increment) the weighted average $/kW cost of the overall microgrid will increase with each increment that is added to the system.

Assuming that NELHA proceeds with a PV+BESS microgrid under this scenario, the NPVs of the cases analyzed will be positive regardless of whether the actual load ends up being in the low, middle, or high end of the assumed range. If NELHA builds out its microgrid based on the low-load assumption and the actual load is at the high end of the range, the financial results generally improve. Conversely if the microgrid is built out based on the high-load assumption and the actual load is at the low end of the range, the financial results are not as strong, but still positive, representing a “no regrets” solution as long as the actual loads are in the assumed range.

3.4 Scenario A.2.n (Research Campus, Economically Prioritized, New Transformer)

3.4.1 Scenario A.2.n Description

As illustrated in Figure 18 below, Scenario A.2.n represents a microgrid to serve only the Research Campus load, utilizing new PV generation that is prioritized in order of economics, and a new HELCO transformer. The fundamental difference between Scenario A.2.e above and this Scenario A.2.n is the use of a new HELCO transformer instead of the existing transformer.

Similar to Scenario A.2.e above, NELHA would need to upgrade the conductors connecting the Power Building roof to the transformer located in the Research Campus Pump Room. This upgrade is estimated to cost approximately $100,000. The total fixed cost for this scenario (with 10% contingency) is approximately $335,000.[16] This cost is inclusive of the new transformer and switchgear, and a new 480 V circuit from the new transformer to the Research Campus Pump Room.

3.4.2 Scenario A.2.n Conclusion

None of the simulations performed under Scenario A.2.n produced economically feasible results (i.e., in no case did XENDEE recommend the addition and any PV generation or storage). The high additional fixed costs attributable to a new HELCO transformer render all of the simulations under Scenario A.2.n economically infeasible. However, similar to Scenario A.1.n, the new transformer would support resiliency in the event of a transformer failure, and the additional investment may be justified from a business perspective.

[16] See Appendix D.

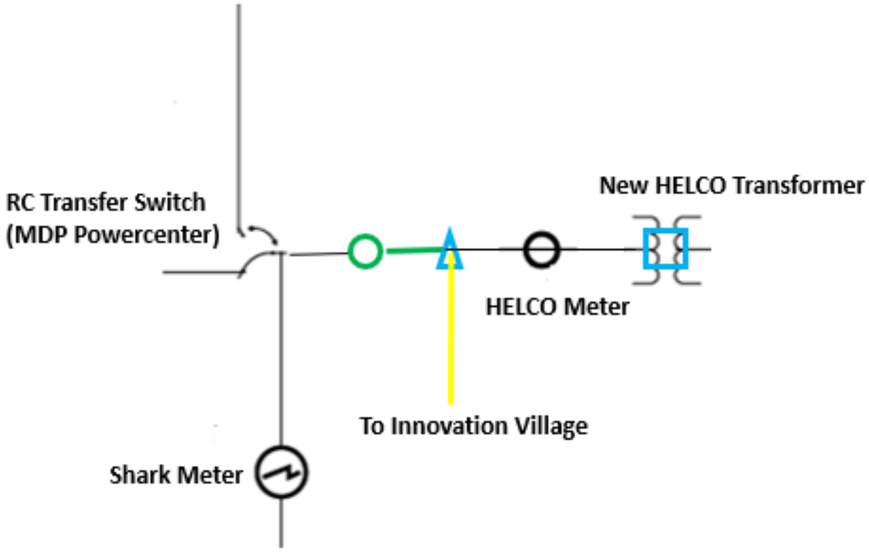


Figure 18: Scenario A.2.n and its Schematic at PoC

3.5 Scenario B.1.e (Research Campus + Farm Compound, Boneyard, Existing Transformer)

3.5.1 Scenario B.1.e Description

As illustrated in Figure 19 below, Scenario B.1.e represents a microgrid that merges the Research Campus and Farm Compound loads under one meter/microgrid, utilizing new PV generation from the Boneyard (prioritized ahead of the PV Test Bed, Power Building roof, Covered Parking Area, Ops Building roof and WQL roof locations) and the existing transformer. As noted in Section 2 above, the Research Campus already has 205 kW of existing PV generation. It is also assumed that because of its relatively lower cost, up to 260 kW of new PV generation would be prioritized at the Innovation Village ahead of any PV installations at the Boneyard.

The key considerations for this scenario are: (1) the cost to connect the Boneyard to the Research Campus/Farm Compound; and (2) the future energy consumption of the Research Campus and Farm Compound facilities. Under this Scenario, a 12.4 kV cable will be required in order to connect the Research Campus switchgear to the Farm Compound switchgear. An additional 12.4 kV cable will be used to connect the Boneyard to the Farm Compound switchgear. The fixed cost to connect the Research Campus and Farm Compound switchgear and a Boneyard PV system to the Farm Compound switchgear is estimated to be $345,000 (including 10% contingency). In a situation where it is economically infeasible to connect the Boneyard to the Research Campus and Farm Compound loads, none of the $345,000 in fixed costs would be incurred, and the electrical configuration for Scenario B.1 would essentially revert to the electrical configuration for Scenario A.1 above.[17]

As was the case under Scenario A, the energy consumption of the Research Campus is expected to have a substantial impact on the overall load under Scenario B. Due largely to the uncertainty of how much electricity the Research Campus will actually consume once the Hydrogen Station is up and running, energy consumption under Scenario B has been evaluated under three load scenarios: (1) low; (2) medium; and (3) high.

[17] See Appendix E.

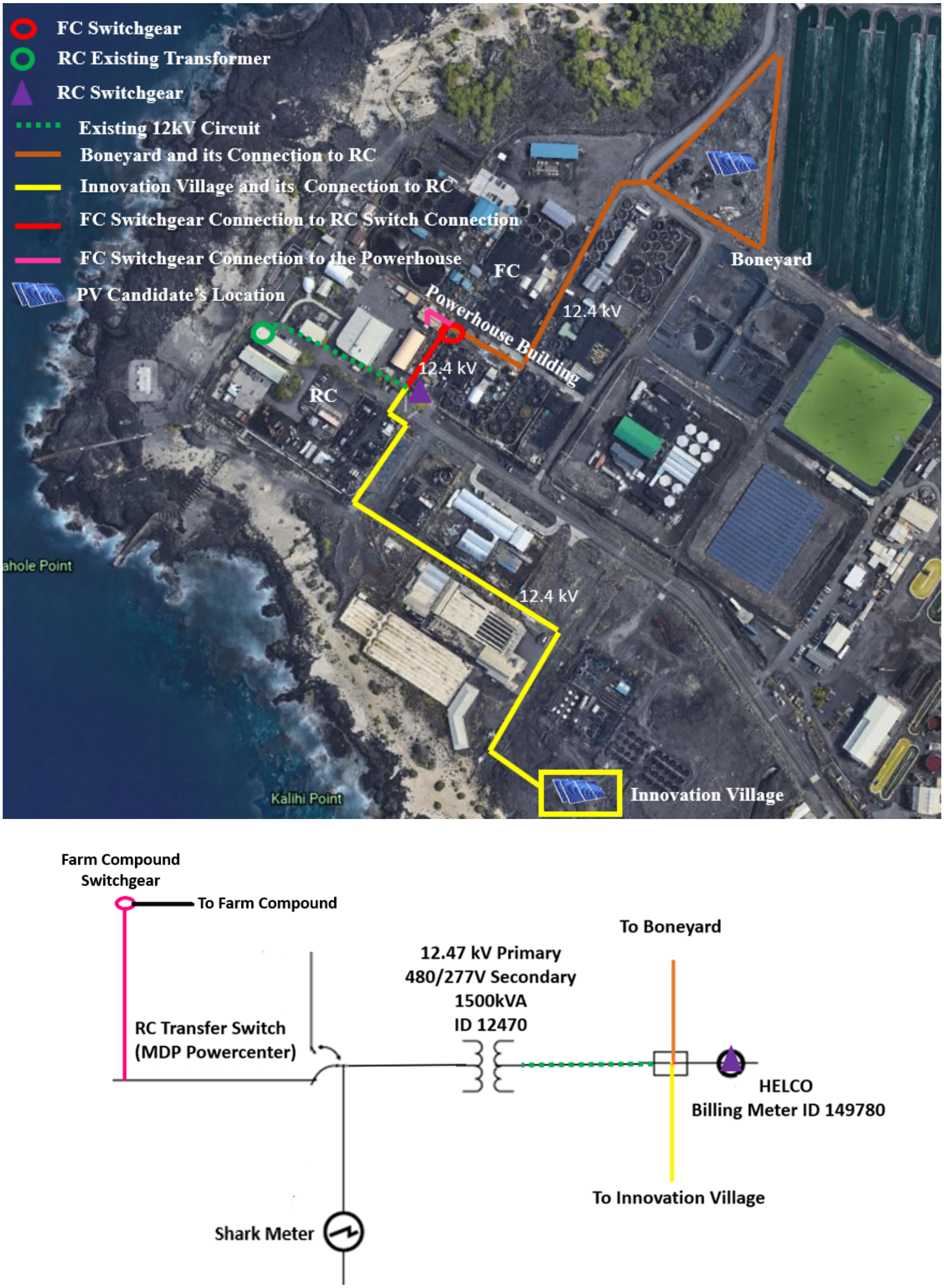


Figure 19: Scenario B.1.e and its Schematic at PoC

3.5.2 Scenario B.1.e Results

Simulation 14:

Load	**Research Campus and Farm Compound**
Prioritized PV Location	**Boneyard**
Transformer	**Existing**
Technology	**PV-Only**
Facilities Production	**Low**
Discount Rate	**6%**

Results:

Location (Max kW)		Existing (205)	Innovation Village (260)	Boneyard (600)	Cum Total Fixed Cost ($)	Cum Total Capex ($000s)	Cum Total kW	Microgrid RE%	Project Payback Period* (simple years, discounted years)
Variable ($/kW)		0	2,500	3,200					
Fixed ($)		0	0	345,000					
XENDEE Optimizations (Incremental kW)									
Increment	0	205	---	---	0	0	205	10	---
	1	205	**260**	---	0	650	465	23	6, 8
	2	205	260	**303**	345,000	**1,965**	**768**	**36**	12, 21
Cum Avg $/kW		---	2,500	3,490	Total Project Payback Period:				9, 14
Capex (in $000s)		---	650	1,315					
NPV (in $000s)		---	729	123	Total NPV (in $000s)				851
IRR (in %)		---	16.2	7	Total IRR (in %)				10.3
Increment		0	1	2					

* *Note: The Project Payback Period is for the incremental addition and is not cumulative.*

Simulation 14 Key Takeaways:

In contrast to Simulations 1 and 2, which did not add any PV generation from the Boneyard under a Research Campus-only low load case, combining the Research Campus and Farm Compound loads results in the addition of 303 kW of solar PV from the Boneyard, even under a low-load, PV-Only case. The ability to now utilize renewable energy at the Farm Compound significantly increases the Microgrid Load Center RE% from 24 in Simulation 1 to 36 in this case.

However, the fixed costs that are actually incurred in connection with the Boneyard increment substantially reduce IRRs when compared to the cases in Simulations 1, 2 and 3 when PV from the Boneyard was excluded from the optimized solution. This particular case results in the lowest NPV ($851,000), but also the lowest capex cost ($1.96 million) of any case under Scenario B.1.e.

Simulation 15:

Load	**Research Campus and Farm Compound**
Prioritized PV Location	**Boneyard**
Transformer	**Existing**
Technology	**PV+BESS**
Facilities Production	**Low**
Discount Rate	**6%**

Results:

Location (Max kW)		Existing (205)	Innovation Village (260)	Boneyard (600)	Cum Total Fixed Cost ($)	Cum Total Capex (PV + BESS) ($000s)	Cum Total kW	Microgrid RE%	Project Payback Period* (simple years, discounted years)
Variable ($/kW)		0	2,500	3,200					
Fixed ($)		0	0	345,000					
XENDEE Optimizations (Incremental kW, Total kWh)									
Increment	0	205, 0	---	---	0	0	205	10	---
	1	205, 0	**260, 61**	---	0	684	465	23	6, 8
	2	205, 0	260, 0	**446, 505**	345,000	**2,700**	**911**	**44**	12, 21
Cum Avg $/kW		---	2,500	3,431	Total Project Payback Period:				9, 14
Capex PV ($000s)		---	650	1,772					
Capex BESS ($000s)		---	34	278					
NPV (in $000s)		---	769	227	Total NPV (in $000s)				976
IRR (in %)		---	16.2	7.2	Total IRR (in %)				9.8
Increment		0	1	2					

** Note: The Project Payback Period is for the incremental addition and is not cumulative.*

Simulation 15 Key Takeaways:

When the possibility of including a BESS is added to the assumptions of Simulation 14 above, 505 kWh of storage is added to the optimized solution – a 450 kWh increase over the Research Campus-only case in Simulation 2. The added storage increases the optimized amount of Boneyard PV generation by 143 kW from 303 kW to 446 kW. This case has the lowest IRR (9.8%) of any case in Scenario B.1.e.

In order to analyze the sensitivity of this case to the low-load assumption, HNEI considered a case where this microgrid was built out based on this optimized low-load sizing (i.e., 911 kW of PV and a 505 kWh BESS) but the actual future load ended up being at the high end of the range. The financial results of such a case are even stronger than the optimized solution, with an NPV of $1.4 million and an IRR of 11.1%. In other words, this is a "no regrets" case provided that the actual future load falls within the assumed range.

Simulation 16:

Load	**Research Campus and Farm Compound**
Prioritized PV Location	**Boneyard**
Transformer	**Existing**
Technology	**PV-Only**
Facilities Production	**Medium**
Discount Rate	**6%**

Results:

Location (Max kW)		Existing (205)	Innovation Village (260)	Boneyard (600)	Cum Total Fixed Cost ($)	Cum Total Capex ($000s)	Cum Total kW	Microgrid RE%	Project Payback Period* (simple years, discounted years)
Variable ($/kW)		0	2,500	3,200					
Fixed ($)		0	0	345,000					
XENDEE Optimizations (Incremental kW)									
Increment	0	205	---	---	0	0	205	9	---
	1	205	**260**	---	0	650	465	21	6, 8
	2	205	260	**398**	345,000	**2,269**	**863**	**37**	11, 18
Cum Avg $/kW		---	2,500	4,023	Total Project Payback Period:				9, 13
Capex (in $000s)		---	650	1,619					
NPV (in $000s)		---	728	287	Total NPV (in $000s)				1,015
IRR (in %)		---	16.2	7.8	Total IRR (in %)				10.4
Increment		0	1	2					

* *Note: The Project Payback Period is for the incremental addition and is not cumulative.*

Simulation 16 Key Takeaways:

When energy consumption at the Research Campus is increased from the low end to the middle of its range, the optimized PV-Only solution increases PV generation at the Boneyard by 95 kW from 303 kW under Simulation 14 to 398 kW. To accommodate the higher Farm Compound/Research Campus load, 398 kW of additional PV generation is added from the Boneyard when compared with the Research Campus-only case in Simulation 3. However, the 863 kV of total PV generation under this case is the lowest of any case in Scenario B.1.e.

Simulation 17:

Load	**Research Campus and Farm Compound**
Prioritized PV Location	**Boneyard**
Transformer	**Existing**
Technology	**PV+BESS**
Facilities Production	**Medium**
Discount Rate	**6%**

Results:

Location (Max kW)		Existing (205)	Innovation Village (260)	Boneyard (600)	Cum Total Fixed Cost ($)	Cum Total Capex (PV + BESS) ($000s)	Cum Total kW	Microgrid RE%	Project Payback Period* (simple years, discounted years)
Variable ($/kW)		0	2,500	3,200					
Fixed ($)		0	0	345,000					
XENDEE Optimizations (Incremental kW, Total kWh)									
Increment	0	205, 0	---	---	0	0	205	9	---
	1	205, 0	**260, 332**	---	0	833	465	22	6, 8
	2	205, 0	260, 0	**528, 425**	345,000	**2,919**	**993**	**43**	11, 16
Cum Avg $/kW		---	2,500	3,406	Total Project Payback Period:				8, 13
Capex PV ($000s)		---	650	2,035					
Capex BESS ($000s)		---	183	234					
NPV (in $000s)		---	810	760	Total NPV (in $000s)				1,470
IRR (in %)		---	16	9.1	Total IRR (in %)				11
Increment		0	1	2					

* *Note: The Project Payback Period is for the incremental addition and is not cumulative.*

Simulation 17 Key Takeaways:

When the possibility of including a BESS is added to the assumptions for Simulation 16 above, PV generation from the Boneyard increases by 130 kW from 398 kW to 528 kW, and the optimized amount of battery storage decreases by 80 kWh from 505 kWh under Simulation 15 to 425 kWh. Even though the 425 kWh BESS under this case is 175 kWh smaller than the BESS analyzed under the Research Campus-only case in Simulation 4, the additional PV generation results in a capex increase from $2.1 million under Simulation 4 to $2.9 million under this case. The 9.1% IRR of the Boneyard increment under this case is stronger than the 7.9% IRR under Simulation 4.

Simulation 18:

Load	**Research Campus and Farm Compound**
Prioritized PV Location	**Boneyard**
Transformer	**Existing**
Technology	**PV-Only**
Facilities Production	**High**
Discount Rate	**6%**

Results:

Location (Max kW)		Existing (205)	Innovation Village (260)	Boneyard (600)	Cum Total Fixed Cost ($)	Cum Total Capex ($000s)	Cum Total kW	Microgrid RE%	Project Payback Period* (simple years, discounted years)
Variable ($/kW)		0	2,500	3,200					
Fixed ($)		0	0	345,000					
XENDEE Optimizations (Incremental kW)									
Increment	0	205	---	---	0	0	205	8	---
	1	205	**260**	---	0	650	465	19	7, 8
	2	205	260	**464**	345,000	**2,480**	**929**	**38**	11, 16
Cum Avg $/kW		---	2,500	3,425	Total Project Payback Period:				9, 13
Capex (in $000s)		---	650	1,830					
NPV (in $000s)		---	702	515	Total NPV (in $000s)				1,218
IRR (in %)		---	15.9	8.8	Total IRR (in %)				10.8
Increment		0	1	2					

* *Note: The Project Payback Period is for the incremental addition and is not cumulative.*

Simulation 18 Key Takeaways:

When the energy consumption under Simulation 16 above is increased from the middle to the high end of its range, the optimized PV-Only solution increases PV generation at the Boneyard from 398 kW to 464 kW. The increased load results in a modest increase in IRR from 10.4% under Simulation 16 to 10.8% under this case.

The size of the 929 kW PV system under this case is 204 kW larger than the 725 kW system analyzed under the Research Campus-only case in Simulation 5. Correspondingly, the $2.5 million capex amount under this case (which also includes higher fixed costs) is higher than the $1.6 million under Simulation 5, and the 10.8% IRR under this case is lower than the 12.8% under Simulation 5.

In order to analyze the sensitivity of this case to the high-load assumption, HNEI considered a case where this microgrid was built out based on this optimized high-load sizing (i.e., 1,065 kW of PV and a 771 kWh BESS) but the actual future load ended up being at the low end of the range. The financial results of such a case are not as strong as the optimized solution, but still positive, with an NPV of $651,000 and an IRR of 8%. In other words, this is a "no regrets" case provided that the actual future load falls within the assumed range.

Simulation 19:

Load	**Research Campus and Farm Compound**
Prioritized PV Location	**Boneyard**
Transformer	**Existing**
Technology	**PV+BESS**
Facilities Production	**High**
Discount Rate	**6%**

Results:

Location (Max kW)		Existing (205)	Innovation Village (260)	Boneyard (600)	Cum Total Fixed Cost ($)	Cum Total Capex (PV + BESS) ($000s)	Cum Total kW	Microgrid RE%	Project Payback Period* (simple years, discounted years)
Variable ($/kW)		0	2,500	3,200					
Fixed ($)		0	0	345,000					
XENDEE Optimizations (Incremental kW, Total kWh)									
Increment	0	205, 0	---	---	0	0	205	8	---
	1	205, 0	**260, 620**	---	0	991	465	20	6, 8
	2	205, 0	260, 0	**600, 771**	345,000	**3,339**	**1,065**	**44**	9, 14
Cum Avg $/kW		---	2,500	3,389	Total Project Payback Period:				8, 12
Capex PV ($000s)		---	650	2,265					
Capex BESS ($000s)		---	341	424					
NPV (in $000s)		---	843	1,032	Total NPV (in $000s)				1,875
IRR (in %)		---	15.4	10.1	Total IRR (in %)				11.5
Increment		0	1	2					

* *Note: The Project Payback Period is for the incremental addition and is not cumulative.*

Simulation 19 Key Takeaways:

When the possibility of including a BESS is added to the assumptions of Simulation 18 above, PV generation from the Boneyard increases from 464 kW to its maximum assumed capacity of 600 kW, and the optimized amount of storage for the overall system increases from 425 kWh (under the medium load case in Simulation 17) to 771 kWh. While utilizing the entire PV generation capacity of the Boneyard adds significant capital expenditure, Simulation 19 has the highest amount of PV (1,065), RE% (44%), NPV ($1.9 million) and IRR (11.5%) among all Scenario B.1.e cases.

The size of the optimized PV system under this combined Research Campus/Farm Compound case is identical to the Research Campus-only case in Simulation 6. However, the size of the 771 kWh BESS in this combined case is 338 kWh smaller than the 1,109 kWh BESS in Simulation 6, due to the Farm Compound's coincident utilization of some of the excess PV production. The $3.3 million of total capex under this case is approximately the same as under Simulation 6 (Research Campus only), and the total NPV of $1.9 million under this case is higher than the $1.7 million under Simulation 6.

3.5.3 Scenario B.1.e Conclusion

Combining the Research Campus and Farm Compound loads increases the $180,000 in fixed costs under the Research Campus-only case in Scenario A.1.e by $165,000 to $345,000 in Scenario B.1.e. The NPVs and IRRs for this Scenario B.1.e are shown below in Figure 20 and Figure 21, respectively. Of note, at each of the assumed loads, the NPVs of the PV+BESS cases are significantly higher than the PV-Only cases (particularly at higher loads).

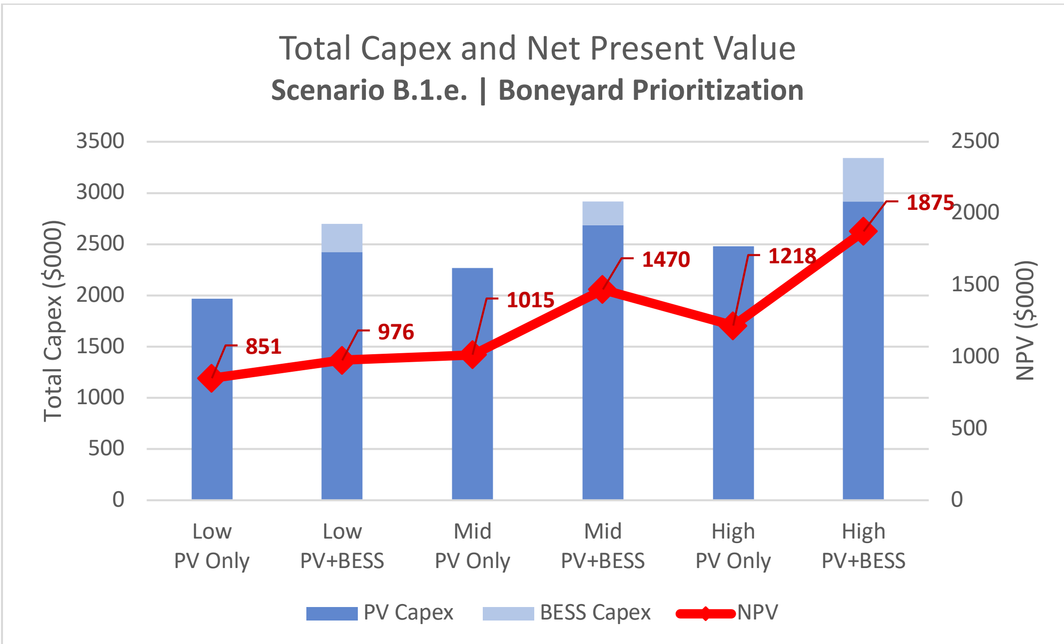


Figure 20: Scenario B.1.e. Capex and NPVs

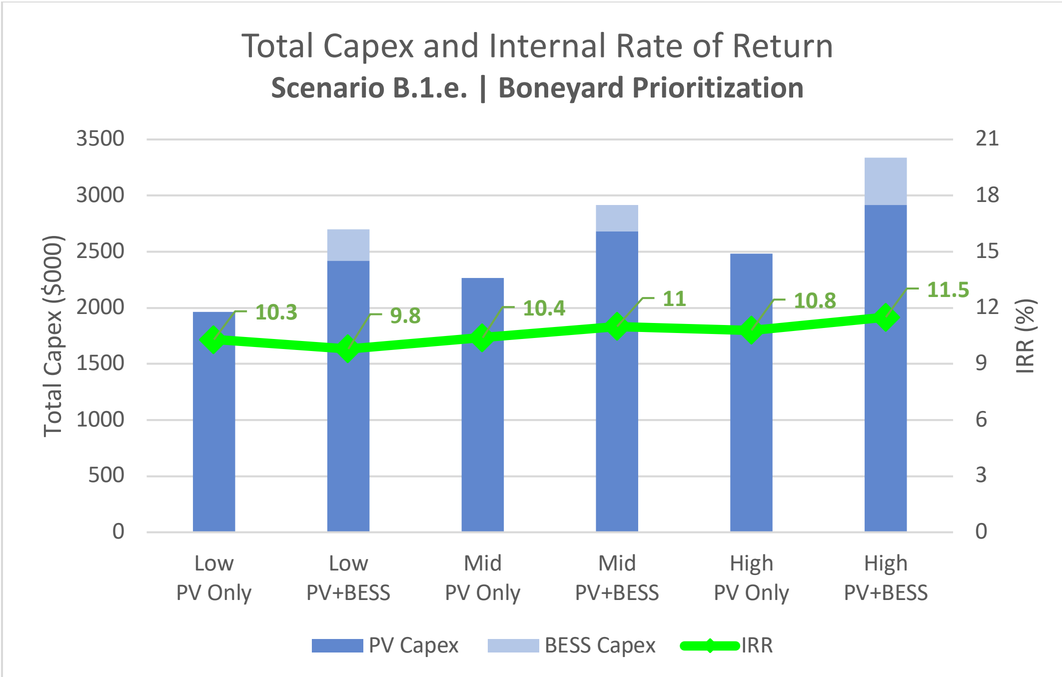


Figure 21: Scenario B.1.e. Capex and NPVs

The simple and discounted payback periods for the PV-Only and PV+BESS cases under this scenario are shown in Figure 22 below. The payback periods are generally shorter in the higher-load and PV+BESS cases.

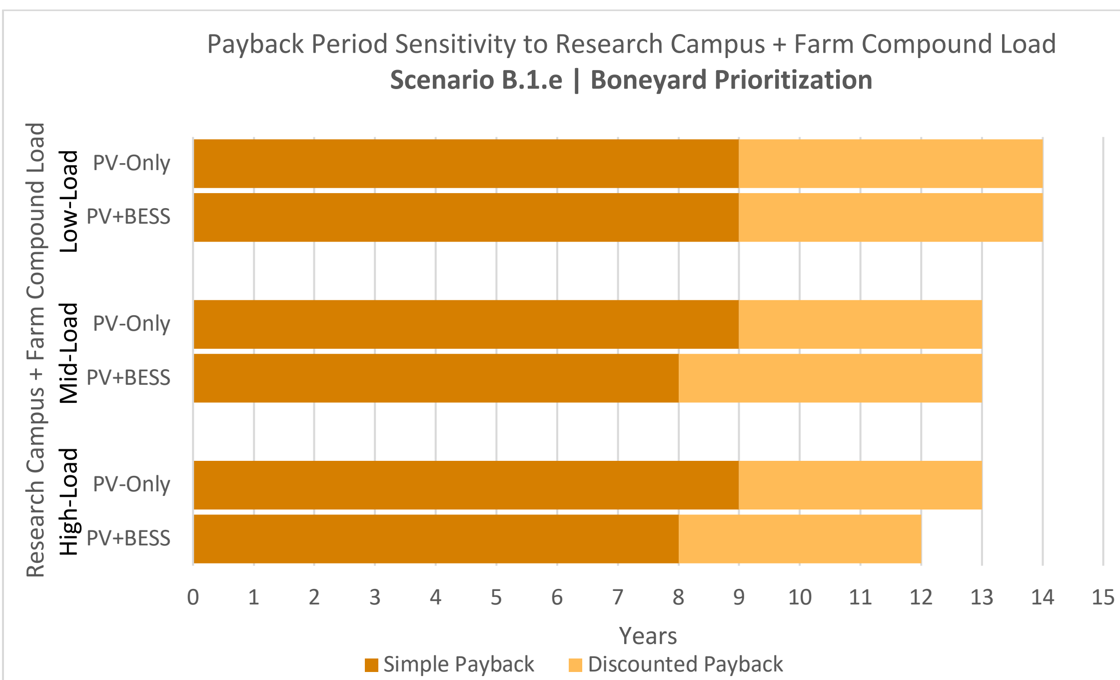


Figure 22: Scenario B.1.e Payback Periods

As shown in Figure 23 below, the combined Research Campus/Farm Compound microgrid generally enables the addition of more PV than the Research Campus-only scenario, especially under lower-load cases. Correspondingly, the Microgrid Load Center RE%s are significantly higher under the combined Scenario B cases than under the unmerged Scenario A cases – particularly at lower loads.

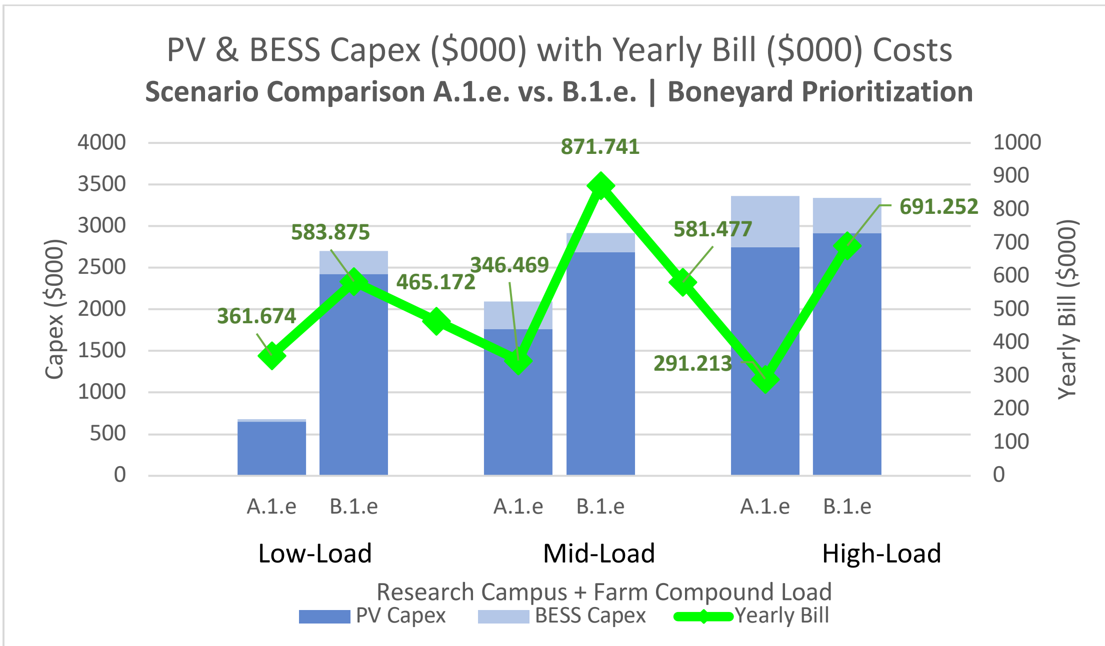


Figure 23: Comparison of Scenario A.1.e and B.1.e PV+BESS Capex

As shown in Figure 23 above, battery sizing is higher under the combined scenario at low loads, but smaller at medium and high loads.

The financial metrics (e.g., NPV and IRR) for the Research Campus-only and combined scenarios are generally comparable except for two key differences: (1) capex is generally higher under the combined scenarios; and (2) the IRRs for the Research Campus-only cases (ranging from 17.8% to 19.2%) are much higher in lower-load cases where fixed investments at the Boneyard are excluded from the optimized results.

NPV is a particularly useful metric for financially comparing the value of a Research Campus-only microgrid to a combined Research Campus/Farm Compound microgrid, as it clearly identifies the instances in which value would be added by merging the two loads under Schedule P. As shown in Table 11 below, when the Boneyard is prioritized (i.e., in Scenarios A.1.e and B.1.e), the NPV of the combined Research Campus/Farm Compound microgrid is higher than the NPV of the Research Campus-only microgrid in all cases except for the Low-Load, PV-Only case.

Table 11: NPV Comparison for the Unmerged (A) and Merged (B) Boneyard Cases

Load, Technology	**NPV ($000s)**	
	Scenario A.1.e	**Scenario B.1.e**
Low, PV-Only	*906*	851
Low, PV+BESS	909	976
Mid, PV-Only	967	1,015
Mid, PV+BESS	1,200	1,470
High, PV-Only	1,160	1,218
High, PV+BESS	1,737	1,875

Given the uncertainly of the future loads at the Research Campus, it appears from the table above that NELHA's "best bet" from a financial perspective would be to implement a combined Research Campus/Farm Compound microgrid utilizing both PV and BESS technologies (particularly if NELHA chooses to implement a PV+BESS microgrid, which would effectively rule out the potential results of the Low-Load, PV-Only case above).

As shown in Figure 24 below, combining the Research Campus and Farm Compound loads under Schedule P also results in lower bills and higher NPVs than if the loads continued to be separately metered.

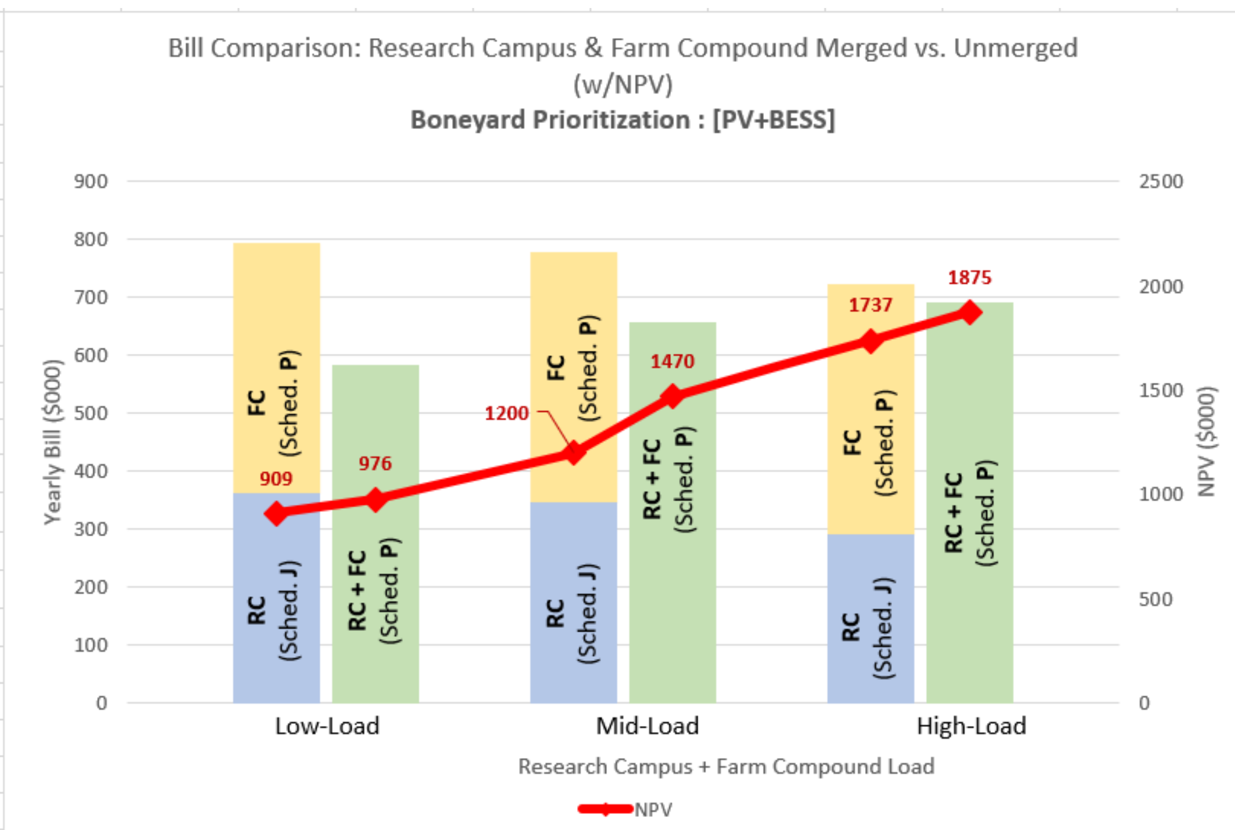


Figure 24: Scenario B.1.e Future Electric Bills Under Unmerged and Merged Cases

Assuming that NELHA proceeds with a PV+BESS microgrid under this scenario, the NPVs of the cases analyzed will be positive regardless of whether the actual load ends up being in the low, middle, or high end of the assumed range. If NELHA builds out its microgrid based on the low-load assumption and the actual load is at the high end of the range, the financial results generally improve. Conversely if the microgrid is built out based on the high-load assumption and the actual load is at the low end of the range, the financial results are not as strong, but still positive, representing a "no regrets" solution as long as the actual loads are in the assumed range.

3.6 Scenario B.1.n (Research Campus + Farm Compound, Boneyard, New Transformer)

3.6.1 Scenario B.1.n Description

As illustrated in Figure 25 below, Scenario B.1.n represents a microgrid to serve the combined Research Campus and Farm Compound loads, utilizing new PV generation from the Boneyard (prioritized ahead of the PV Test Bed, Power Building roof, Covered Parking Area, Ops Building roof and WQL roof locations) and a new HELCO transformer. The fundamental difference between Scenario B.1.e above and this Scenario B.1.n is the use of a new HELCO transformer instead of the existing NELHA transformer. As noted in Section 3.2 above, the impetus for analyzing a scenario with a new transformer is NELHA's stated desire for additional resiliency in the event of a transformer failure.

The new transformer increases the estimated fixed cost for the combined Research Campus/Farm Compound microgrid by $455,000 from $345,000 under Scenario B.1.e to $800,000 under Scenario B.1.n.[18] This increase is attributable to costs associated with replacing the transformer, its related conductors, new connection lines and switchgear upgrades. The increased fixed costs render Scenario B.1.n economically infeasible in XENDEE under the low-load cases, as well as under the medium- and high-load PV-Only cases. As a result, Simulations 20, and 21 below only address Scenario B.1.n under the mid- and high-load PV+BESS cases.

[18] See Appendix F.

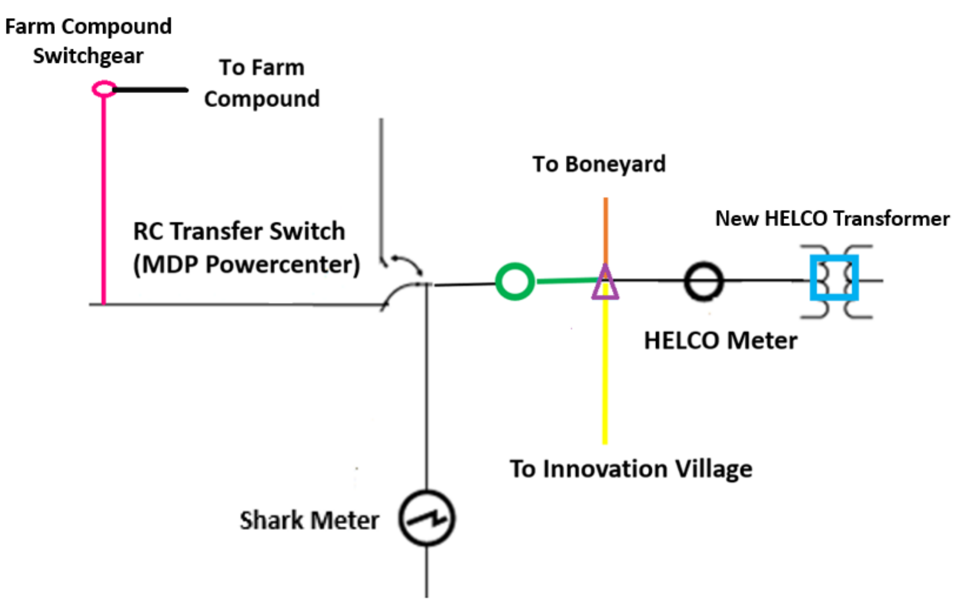


Figure 25: Scenario B.1.n and its Schematic at PoC

Simulation 20:

Load	**Research Campus and Farm Compound**
Prioritized PV Location	**Boneyard**
Transformer	**New**
Technology	**PV+BESS**
Facilities Production	**Medium**
Discount Rate	**6%**

Results:

Location (Max kW)		Existing (205)	Innovation Village (260)	Boneyard (600)	Cum Total Fixed Cost ($)	Cum Total Capex (PV + BESS) ($000s)	Cum Total kW	Microgrid RE%	Project Payback Period* (simple years, discounted years)
Variable ($/kW)		0	2,500	3,200					
Fixed ($)		0	0	800,000					
XENDEE Optimizations (Incremental kW, Total kWh)									
Increment	0	205, 0	---	---	---	0	205	9	---
	1	205, 0	**260, 332**	---	0	833	465	21	6, 8
	2	205, 0	260, 0	**589, 664**	800,000	**3,700**	**1,054**	**46**	13, 23
Cum Avg $/kW		---	2,500	3,920	Total Project Payback Period:				11, 16
Capex PV ($000s)		---	650	2,685					
Capex BESS ($000s)		---	183	365					
NPV (in $000s)		---	811	194	Total NPV (in $000s)				1,005
IRR (in %)		---	16	6.7	Total IRR (in %)				8.8
Increment		0	1	2					

* *Note: The Project Payback Period is for the incremental addition and is not cumulative.*

Simulation 20 Key Takeaways:

The cost of adding a new HELCO transformer more than doubles the fixed cost of the Boneyard increment in Scenario B.1.e to $800,000 in Scenario B.1.n, thereby rendering Scenario B.1.n economically infeasible in XENDEE under the low load cases, as well as under the medium and high load PV-Only cases. Under this mid-load PV+BESS case the optimized solution includes 589 kW of PV generation at the Boneyard (compared to 528 kW in Simulation 17), and 664 kWh of storage (compared to 425 kWh in Simulation 17). The 8.8% IRR of this case is lower than any case in Scenario B.1.e (but still well-above the assumed Loan Interest Rate of 6%).

Simulation 21:

Load	**Research Campus and Farm Compound**
Prioritized PV Location	**Boneyard**
Transformer	**New**
Technology	**PV+BESS**
Facilities production	**High**
Discount Rate	**6%**

Results:

Location (Max kW)		Existing (205)	Innovation Village (260)	Boneyard (600)	Cum Total Fixed Cost ($)	Cum Total Capex (PV + BESS) ($000s)	Cum Total kW	Microgrid RE%	Project Payback Period* (simple years, discounted years)
Variable ($/kW)		0	2,500	3,200					
Fixed ($)		0	0	800,000					
XENDEE Optimizations (Incremental kW, Total kWh)									
Increment	0	205, 0	---	---	0	0	205	8	---
	1	205, 0	**260, 620**	---	0	991	465	19	6, 8
	2	205, 0	260, 0	**600, 771**	800,000	**3,794**	**1,065**	**44**	12, 18
Cum Avg $/kW		---	2,500	3,918	Total Project Payback Period:				9, 14
Capex PV ($000s)		---	650	2,720					
Capex BESS ($000s)		---	341	424					
NPV (in $000s)		---	843	578	Total NPV (in $000s)				1,420
IRR (in %)		---	15.4	8	Total IRR (in %)				9.7
Increment		0	1	2					

* *Note: The Project Payback Period is for the incremental addition and is not cumulative.*

Simulation 21 Key Takeaways:

When energy consumption at the Research Campus/Farm Compound is increased from the middle to the high end of its range, the optimized PV+BESS solution increases PV generation from the Boneyard to its maximum capacity of 600 kW, and the optimized amount of storage for the overall system increases from 664 kWh (under the medium load case in Simulation 20) to 771 kWh. The 9.7% IRR in this case is materially higher than the 8.8% IRR in Simulation 20 (i.e., the mid load case), but still lower than any case in Scenario B.1.e.

3.6.2 Scenario B.1.n Conclusion

The high fixed cost of electrically connecting PV generation at the Boneyard to the Research Campus/Farm Compound switchgear renders Scenario B.1.n economically infeasible in XENDEE under all PV-Only cases, and only feasible under the mid- and high-load PV+BESS cases. Compared to Scenario B.1.e, replacing the existing transformer with a new HELCO transformer adds significant costs to the microgrid design. However, similar to Scenarios A.1.n and A.2.n, the cost of investing in a new transformer may be justified from a resiliency/business standpoint.

3.7 Scenario B.2.e (Research Campus + Farm Compound, Economically Prioritized, Existing Transformer)

3.7.1 Scenario B.2.e Description

As illustrated in Figure 26 below, Scenario B.2.e represents a microgrid that merges the Research Campus and Farm Compound loads under one meter, utilizing new PV generation from the Innovation Village and various other sites within the Research Campus, and the existing transformer. Under this scenario, additional increments of PV generation are economically prioritized based on their all-in average $/kW cost as follows: (1) Innovation Village; (2) PV Test Bed; (3) Power Building roof; (4) Covered Parking Area; (5) Ops Building roof; (6) WQL roof; (7) Pipeline Area; and (8) Boneyard.[19]

Similar to the Scenario B.1.e cases that prioritized PV generation at the Boneyard, the future energy consumption of the Research Campus and Farm Compound is a key consideration affecting the economics of the microgrid configurations and has been evaluated under three load scenarios: (1) low; (2) medium; and (3) high.

Prioritizing PV locations in order of economics (versus prioritizing the Boneyard in Scenarios A.1 and B.1) results in substantially stronger financial metrics. The bottom row of Table 4 above economically ranks the Scenario B.2.e locations other than the Boneyard in order of "All-In Average Cost ($/kW)", ranging from $2,500/kW at the Innovation Village to $3,580 for the Pipeline Area. Those rankings assume the maximum "PV System Size" identified in the top row of Table 4. The All-In Average Cost ($/kW) for the Boneyard of $3,740/kW is similarly presented in Table 5 above, and therefore the Boneyard ranks last in order of economic priority in this Scenario B.2.e.

It should be noted that Table 3 above includes $100,000 in costs for "Electrical Upgrades to Existing Infrastructure ($) (fixed)" that are allocated on a per-kW basis among the Power Building roof, Ops Building roof and Covered Parking Area locations. Those costs are not included in this Scenario B.2.e, as those upgrades are not necessary if NELHA decides to connect Research Campus to the Farm Compound. The removal of those costs from the simulations below results in the Covered Parking area becoming a slightly more economical PV location than the Ops Building roof – a "flip-flop" of the economic priority presented in Table 3. As detailed in Appendix G, this scenario also includes approximately $43,000 in fixed costs, which are allocated to applicable locations in proportion to their maximum PV capacities.

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[19] Fixed costs are distributed as follows: (1) Cost associated with PV installation at each location (Table 4) + (2) Fixed cost for the new HELCO transformer ($564,000) – distributed according to max kW of location.

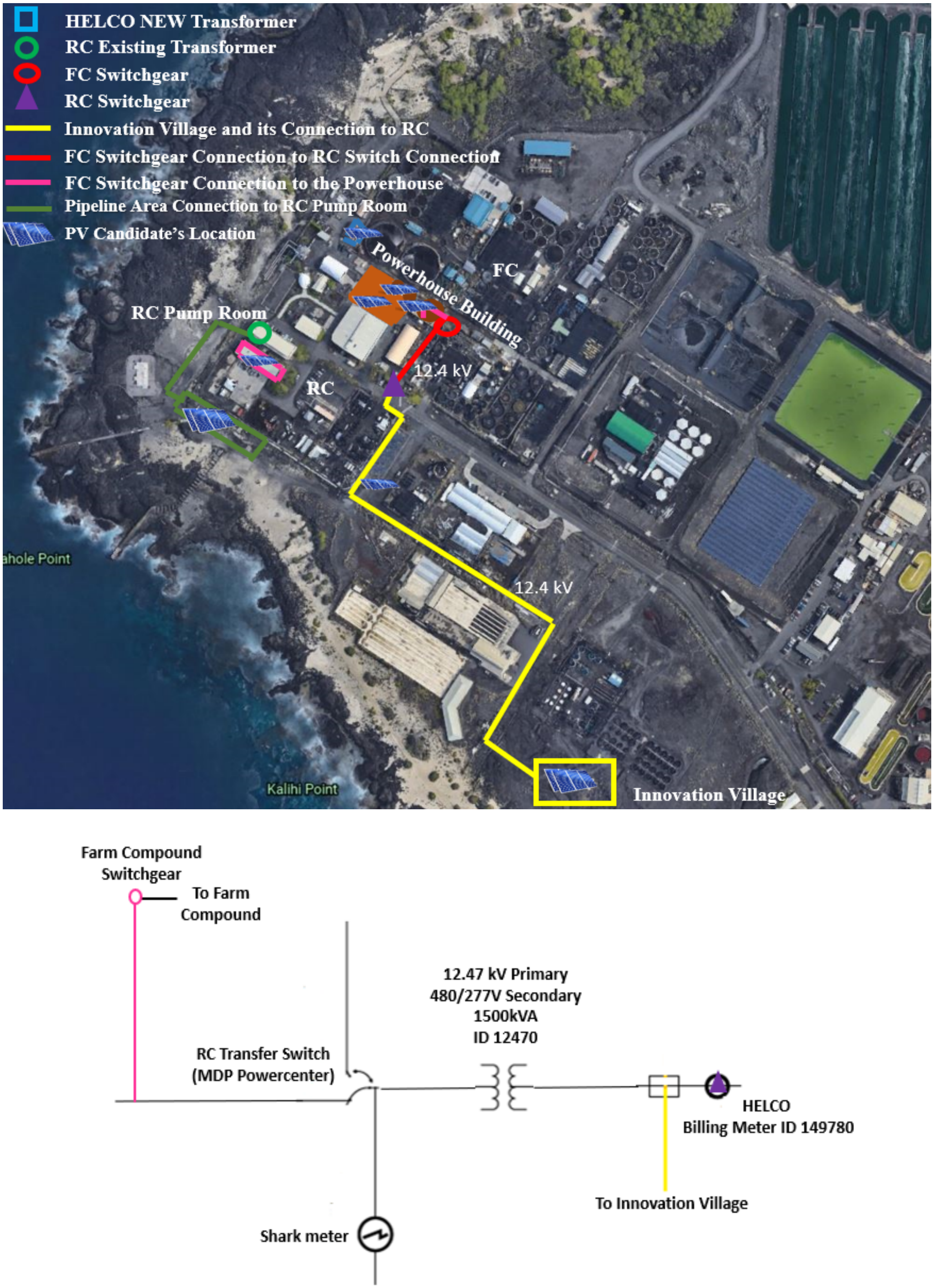

Figure 26: Scenario B.2.e and its Schematic

3.7.2 Scenario B.2.e Results

Simulation 22:

Load	**Research Campus and Farm Compound**
PV Location Prioritization	**By Average $/kW**
Transformer	**Existing**
Technology	**PV-Only**
Facilities Production	**Low**
Discount Rate	**6%**

Results:

Location (max kW)		Existing (205)	Innovation Village (260)	PV Test Bed (8)	Power Bldg Roof (40)	Covered Parking (96)	Ops Bldg Roof (14)	NELHA WQL Roof (51)	Pipeline Area (123)	Cum Total Fixed Cost ($)	Cum Total Capex ($000s)	Cum Total kW	Microgrid RE%	Project Payback Period* (simple years, discounted years)
Variable ($/kW)		0	2,500	3,000	2,500	3,300	2,500	2,500	3,200					
Fixed ($)		0	0	0 + 1000	28,850+ 8000	10,000+ 20,000	12,300+ 3,000	52,000+ 10,500	55,000					
XENDEE Optimizations (Incremental kW)														
Increments	0	205	---	---						0	0	205	10	---
	1	205	**260**	---						0	650	465	23	6, 8
	2	205	260	**8**						1,000	675	473	23	7, 8
	3	205	260	8	**40**					38,274	812	513	26	9, 12
	4	205	260	8	40	**96**				67,850	1,159	609	31	9, 14
	5	205	260	8	40	96	**14**			83,150	1,209	623	31	8, 11
	6	205	260	8	40	96	14	**51**		145,650	**1,399**	**674**	**34**	10, 16
	7	205	260	8	40	96	14	51	**0**	---	**---**	**---**	**---**	**---**
Cum Avg $/kW		---	2,500	2,515	2,633	2,866	2,890	2,981	---	Total Project Payback Period				8, 10
Capex PV (in $000s)		---	650	25	137	347	50	190	---					
NPV (in $000s)		---	729	46	73	150	45	58	---	Total NPV (in $000s)				1,102
IRR (in %)		---	16.2	16.1	11.1	10.2	12.5	9.1	---	Total IRR (in %)				13.2
Increments		0	1	2	3	4	5	6	7					

* *Note: The Project Payback Period is for the incremental addition and is not cumulative.*

Simulation 22 Key Takeaways:

Economically prioritizing PV sites by all-in variable cost (based on optimized levels of PV) for a merged Research Campus/Farm Compound scenario under a PV-Only, low-load case, results in the addition of all of the available PV generation from the Innovation Village, PV Test Bed, Power Building roof, Covered Parking Area, Ops Building roof, and WQL roof. This case stops short of adding any PV from the Pipeline Area or Boneyard.

The $1.4 million capex cost under this case is the lowest of any case in Scenario B.2.e, and $500,000 lower than the $1.9 million capex cost where the Boneyard was prioritized in Simulation 14. However, the size of the 674 kW PV system under this case is the smallest of any case in Scenario B.2.e, and smaller than the 768 kW system under Simulation 14. Although this case has the lowest NPV ($1.1 million) of any case in Scenario B.2.e, it also has the highest IRR (13.2%) of any case in Scenario B.2.e.

Simulation 23:

Load	**Research Campus and Farm Compound**
PV Location Prioritization	**By Average $/kW**
Transformer	**Existing**
Technology	**PV+BESS**
Facilities Production	**Low**
Discount Rate	**6%**

Results:

Location (max kW)		Existing (205)	Innovation Village (260)	PV Test Bed (8)	Power Bldg Roof (40)	Covered Parking (96)	Ops Bldg Roof (14)	NELHA WQL Roof (51)	Pipeline Area (123)	Cum Total Fixed Cost ($)	Cum Total Capex ($000s)	Cum Total kW	Microgrid RE%	Project Payback Period* (simple years, discounted years)
Variable ($/kW)		0	2,500	3,000	2,500	3,300	2,500	2,500	3,200					
Fixed ($)		0	0	0 + 1,000	28,850 + 5,000	10,000 + 12,500	12,300 + 2,000	52,000 + 7,000	55,000+ 16,000					
XENDEE Optimizations (Incremental kW, Total kWh)														
Increments	0	205, 0	---	---	---	---	---	---	---	0	0	205	10	---
	1	205, 0	**260, 61**	---	---	---	---	---	---	0	684	465	23	7, 9
	2	205, 0	260, 0	**8, 61**	---	---	---	---	---	1,000	709	473	23	7, 8
	3	205, 0	260, 0	8,	**40, 62**	---	---	---	---	37,000	843	513	26	8, 12
	4	205, 0	260, 0	8, 0	40, 0	**96, 65**	---	---	---	109,000	1,184	609	31	9, 13
	5	205, 0	260, 0	8, 0	40, 0	96, 0	**14, 65**	---	---	143,500	1,233	623	31	7, 12
	6	205, 0	260, 0	8, 0	40, 0	96, 0	14, 0	**51, 67**	---	156,500	1,421	674	34	9, 14
	7	205, 0	260, 0	8, 0	40, 0	96, 0	14, 0	51, 0	**112, 184**	**157,500**	**1,914**	**786**	**39**	12, 19
Cum Avg $/kW		---	2,500	2,515	2,623	2,840	2,863	2,949	2,988	Total Project Payback Period				8, 12
Capex PV (in $000s)		---	650	25	134	339	49	187	429					
Capex BESS (in $000s)		---	34	34	34	36	36	37	101					
NPV (in $000s)		---	686	33	84	175	42	91	76	Total NPV (in $000s)				1,182
IRR (in %)		---	14.7	13.5	11.4	10.8	12	10.3	7.5	Total IRR (in %)				11.6
Increments		0	1	2	3	4	5	6	7					

** Note: The Project Payback Period is for the incremental addition and is not cumulative.*

Simulation 23 Key Takeaways:

When the possibility of including a BESS is added to the assumptions for Simulation 23 above, the optimized solution includes 112 kW of the available PV capacity from the Pipeline Area. The 786 kW PV system under this case is smaller than the 911 kW system when the Boneyard was prioritized in Simulation 15. The 184 kWh battery under this case is less than half the size of the 505 kWh battery in Simulation 15. The 11.6% IRR of this case is the lowest of all of the Scenario B.2.e cases, but higher than the 9.8% IRR for Simulation 15, which is an indication of the economic benefits of prioritizing PV locations based on economics (versus prioritizing the Boneyard). The RE% of 39% under this case is the highest of any in Scenario B.2.e.

In order to analyze the sensitivity of this case to the low-load assumption, HNEI considered a case where this microgrid was built out based on this optimized low-load sizing (i.e., 786 kW of PV and a 184 kWh BESS) but the actual future load ended up being at the high end of the range. The financial results of such a case are even stronger than the optimized solution, with an NPV of $1.4 million and an IRR of 12.5%. In other words, this is a “no regrets” case provided that the actual future load falls within the assumed range.

Simulation 24:

Load	**Research Campus and Farm Compound**
PV Location Prioritization	**By Average $/kW**
Transformer	**Existing**
Technology	**PV-Only**
Facilities Production	**Medium**
Discount Rate	**6%**

Results:

Location (max kW)		Existing (205)	Innovation Village (260)	PV Test Bed (8)	Power Bldg Roof (40)	Covered Parking (96)	Ops Bldg Roof (14)	NELHA WQL Roof (51)	Pipeline Area (123)	Cum Total Fixed Cost ($)	Cum Total Capex ($000s)	Cum Total kW	Microgrid RE%	Project Payback Period* (simple years, discounted years)
Variable ($/kW)		0	2,500	3,000	2,500	3,300	2,500	2,500	3,200					
Fixed ($)		0	0	0 + 1,000	28,850+ 5,000	10,000+ 12,500	12,300+ 2,000	52,000+ 7,000	55,000+ 16,000					
XENDEE Optimizations (Incremental kW, Total kWh)														
Increments	0	205	---	---						0	0	205	9	---
	1	205	**260**	---						0	650	465	23	6, 8
	2	205	260	**8**						1,000	675	473	23	6, 7
	3	205	260	8	**40**					34,850	809	513	23	9, 12
	4	205	260	8	40	**96**				57,350	1,148	609	27	9, 14
	5	205	260	8	40	96	**14**			71,650	1,197	623	27	7, 12
	6	205	260	8	40	96	14	**51**		130,650	1,384	674	30	10, 14
	7	205	260	8	40	96	14	51	**123**	201,650	**1,849**	**797**	**35**	11, 17
Cum Avg $/kW		---	2,500	2,515	2,623	2,840	2,863	2,949	3,121	Total Project Payback Period				8, 11
Capex PV (in $000s)		---	650	25	134	339	49	187	465					
NPV (in $000s)		---	728	59	73	149	42	73	112	Total NPV (in $000s)				1,235
IRR (in %)		---	16.2	18.6	11.1	10.2	12	9.9	8.4	Total IRR (in %)				12.2
Increments		0	1	2	3	4	5	6	7					

** Note: The Project Payback Period is for the incremental addition and is not cumulative.*

Simulation 24 Key Takeaways:

When energy consumption is increased from the low end to the middle of its range, the optimized PV-Only solution adds the remaining 11 kW of available PV capacity from the Pipeline Area that was excluded under Simulation 23. This case utilizes the entire PV generation capacity of all Research Campus locations, except for the Boneyard. None of the subsequent cases under this Scenario B.2.e add any PV in excess of the 797 kW that is reflected in this case.

The total capex cost under this case of $1.85 million is $419,000 less than the capex cost of $2,269,000 under Simulation 16 when the Boneyard was prioritized. The NPV and IRR for this case are both greater than for Simulation 16 – again reflecting the benefits of prioritizing PV locations based on economics.

Simulation 25:

Load	**Research Campus and Farm Compound**
PV Location Prioritization	**By Average $/kW**
Transformer	**Existing**
Technology	**PV+BESS**
Facilities Production	**Medium**
Discount Rate	**6%**

Results:

Location (max kW)		Existing (205)	Innovation Village (260)	PV Test Bed (8)	Power Bldg Roof (40)	Covered Parking (96)	Ops Bldg Roof (14)	NELHA WQL Roof (51)	Pipeline Area (123)	Cum Total Fixed Cost ($)	Cum Total Capex ($000s)	Cum Total kW	Microgrid RE%	Project Payback Period* (simple years, discounted years)
Variable ($/kW)		0	2,500	3,000	2,500	3,300	2,500	2,500	3,200					
Fixed ($)		0	0	0 + 1,000	28,850 + 5,000	10,000 + 12,500	12,300 + 2,000	52,000 + 7,000	55,000+ 16,000					
XENDEE Optimizations (Incremental kW, Total kWh)														
Increments	0	205, 0	---	---	---	---	---	---	---	0	0	205	9	---
	1	205, 0	**260, 332**	---	---	---	---	---	---	0	833	465	21	6, 8
	2	205, 0	260, 0	**8, 333**	---	---	---	---	---	1,000	858	473	21	6, 7
	3	205, 0	260, 0	8, 0	**40, 338**	---	---	---	---	34,850	995	513	23	9, 12
	4	205, 0	260, 0	8, 0	40, 0	**96, 351**	---	---	---	57,350	1,341	609	27	8, 13
	5	205, 0	260, 0	8, 0	40, 0	96, 0	**14, 352**	---	---	71,650	1,319	623	28	6, 8
	6	205, 0	260, 0	8, 0	40, 0	96, 0	14, 0	**51, 356**	---	130,650	1,580	674	30	7, 9
	7	205, 0	260, 0	8, 0	40, 0	96, 0	14, 0	51, 0	**123, 371**	201,650	**2,054**	**797**	**39**	8, 13
Cum Avg $/kW		---	2,500	2,515	2,623	2,840	2,863	2,949	2,988	Total Project Payback Period				7, 9
Capex PV (in $000s)		---	650	25	134	339	49	187	429					
Capex BESS (in $000s)		---	34	34	34	36	36	37	101					
NPV (in $000s)		---	686	33	84	175	42	91	76	Total NPV (in $000s)				1,800
IRR (in %)		---	14.7	13.5	11.4	10.8	12	10.3	7.5	Total IRR (in %)				13
Increments		0	1	2	3	4	5	6	7					

* *Note: The Project Payback Period is for the incremental addition and is not cumulative.*

Simulation 25 Key Takeaways:

When the possibility of including a BESS is added to the assumptions for Simulation 24 above, the optimized solution continues to utilize all of the available PV capacity from the Innovation Village, PV Test Bed, Power Building roof, Covered Parking Area, Ops Building roof, WQL roof and Pipeline Area, but stops short of adding any additional PV generation from the Boneyard.

When compared to the low-load PV+BESS case in Simulation 23, the increase to medium load in this case results in the addition of 11 kW of PV generation; however, the size of the BESS increases from 184 kWh to 371 kWh, which increases the capex cost from $1.9 million in Simulation 23 to $2.0 million in this case.

Once again, the financial metrics of this economically-prioritized case are considerably stronger than the case where the Boneyard location was prioritized in Simulation 17. The NPV and IRR for this case are both greater than for Simulation 17.

Simulation 26:

Load	**Research Campus and Farm Compound**
PV Location Prioritization	**By Average $/kW**
Transformer	**Existing**
Technology	**PV-Only**
Facilities Production	**High**
Discount Rate	**6%**

Results:

Location (max kW)	Existing (205)	Innovation Village (260)	PV Test Bed (8)	Power Bldg Roof (40)	Covered Parking (96)	Ops Bldg Roof (14)	NELHA WQL Roof (51)	Pipeline Area (123)	Cum Total Fixed Cost ($)	Cum Total Capex ($000s)	Cum Total kW	Microgrid RE%	Project Payback Period* (simple years, discounted years)
Variable ($/kW)	0	2,500	3,000	2,500	3,300	2,500	2,500	3,200					
Fixed ($)	0	0	0 + 1,000	28,850+ 5,000	10,000+ 12,500	12,300+ 2,000	52,000+ 7,000	55,000+ 16,000					
XENDEE Optimizations (Incremental kW)													
Increments 0	205	---	---						0	0	205	8	---
1	205	**260**	---						0	650	465	19	7, 8
2	205	260	**8**						1,000	675	473	19	6, 7
3	205	260	8	**40**					34,850	809	513	21	9, 12
4	205	260	8	40	**96**				57,350	1,148	609	25	9, 13
5	205	260	8	40	96	**14**			71,650	1,197	623	25	7, 12
6	205	260	8	40	96	14	**51**		130,650	1,384	674	28	10, 14
7	205	260	8	40	96	14	51	**123**	201,650	**1,849**	**797**	**35**	10, 15
Cum Avg $/kW	---	2,500	2,515	2,623	2,840	2,863	2,949	3,121	Total Project Payback Period				8, 11
Capex PV (in $000s)	---	650	25	134	339	49	187	465					
NPV (in $000s)	---	728	59	73	149	42	73	112	Total NPV (in $000s)				1,277
IRR (in %)	---	16.2	18.6	11.1	10.2	12	9.9	8.4	Total IRR (in %)				12.4
Increments	0	1	2	3	4	5	6	7					

** Note: The Project Payback Period is for the incremental addition and is not cumulative.*

Simulation 26 Key Takeaways:

When the energy consumption in Simulation 24 above is increased from the middle to the high end of its range, the optimized PV-Only solution remains constant at 797 kW of generation and continues to stop short of adding any PV generation from the Boneyard. Therefore, the capex cost also remains the same as for Simulation 24.

Although the $1.85 million NPV for this case is lower than the $2.5 million NPV for Simulation 18 (when the Boneyard was prioritized), the 12.7% IRR for this case is higher than the 10.8% IRR for Simulation 18 (which is reflective of a better return on investment).

It should also be noted that the Microgrid Load Center RE% of 33 in this high-load case (see also Simulation 27 below) is lower than the Microgrid Load Center RE% of 39 in the mid-load case of Simulation 25, due to increased reliance on energy from the HELCO grid to power the Hydrogen Station.

Simulation 27:

Load	**Research Campus and Farm Compound**
PV Location Prioritization	**By Average $/kW**
Transformer	**Existing**
Technology	**PV + BESS**
Facilities Production	**High**
Discount Rate	**6%**

Results:

Location (max kW)		Existing (205)	Innovation Village (260)	PV Test Bed (8)	Power Bldg Roof (40)	Covered Parking (96)	Ops Bldg Roof (14)	NELHA WQL Roof (51)	Pipeline Area (123)	Cum Total Fixed Cost ($)	Cum Total Capex ($000s)	Cum Total kW	Microgrid RE%	Project Payback Period* (simple years, discounted years)
Variable ($/kW)		0	2,500	3,000	2,500	3,300	2,500	2,500	3,200					
Fixed ($)		0	0	0 + 1,000	28,850 + 5,000	10,000 + 12,500	12,300 + 2,000	52,000 + 7,000	55,000+ 16,000					
XENDEE Optimizations (Incremental kW, Total kWh)														
Increments	0	205, 0	---	---	---	---	---	---	---	0	0	205	8	---
	1	205, 0	**260, 571**	---	---	---	---	---	---	0	964	465	19	6, 8
	2	205, 0	260, 0	**8, 578**	---	---	---	---	---	1,000	993	473	19	6, 7
	3	205, 0	260, 0	8, 0	**40, 606**	---	---	---	---	34,850	1,142	524	21	7, 8
	4	205, 0	260, 0	8, 0	40, 0	**96, 705**	---	---	---	57,350	1,486	647	25	7, 9
	5	205, 0	260, 0	8, 0	40, 0	96, 0	**14, 710**	---	---	71,650	1,588	687	26	6, 7
	6	205, 0	260, 0	8, 0	40, 0	96, 0	14, 0	**51, 720**	---	130,650	1,780	783	28	7, 9
	7	205, 0	260, 0	8, 0	40, 0	96, 0	14, 0	51, 0	**123, 740**	201,650	**2,256**	**797**	**33**	8, 13
Cum Avg $/kW		---	2,500	2,515	2,623	2,840	2,863	2,949	3,121	Total Project Payback Period				7, 9
Capex PV (in $000s)		---	650	25	134	339	49	187	465					
Capex BESS (in $000s)		---	314	318	333	388	391	396	407					
NPV (in $000s)		---	813	130	202	300	178	233	351	Total NPV (in $000s)				2,210
IRR (in %)		---	15.2	12.8	12.4	11.4	13	11.8	11.1	Total IRR (in %)				12.7
Increments		0	1	2	3	4	5	6	7					

* *Note: The Project Payback Period is for the incremental addition and is not cumulative.*

Simulation 27 Key Takeaways:

When the possibility of including a BESS is added to the assumptions of Simulation 26 above, the optimized solution continues to stop short of adding any PV generation from the Boneyard, but the optimized amount of storage increases from 371 kWh (under the medium load case in Simulation 25) to 740 kWh under this case. The additional storage capacity increases the capex by $407,000 (when compared to the PV-Only case in Simulation 26) to $2.25 million, which is the highest capex of any case in Scenario B.2.e. Notwithstanding the high capex costs, this case has the highest NPV ($2.2 million) of any case under Scenarios A and B.

This case results in the highest financial risk, but also the highest financial reward of any case in Scenarios A and B. In order to analyze the sensitivity of this case to the high-load assumption, HNEI considered a case where this microgrid was built out based on this optimized high-load sizing (i.e., 797 kW of PV and a 740 kWh BESS) but the actual future load ended up being at the low end of the range. In this case, the under-utilization of the relatively large BESS results in an NPV of -$784,000 and an IRR of 3.1%. In other words, this investment would be "out of the money" unless, for example, NELHA's cost of capital were reduced from 6% to 3%, or the actual load were at least in the middle of the assumed range.

3.7.3 Scenario B.2.e Conclusion

The relatively low fixed cost of installing PV generation at the PV Test Bed, Power Building roof, Covered Parking Area, Ops Building roof, WQL roof and Pipeline Area result in Scenario B.2.e being much more economical than the cases where the Boneyard was prioritized in Scenario B.1.e. When compared to Scenario A.2.e, combining the Research Campus and Farm Compound loads increases the $107,000 in fixed costs under the Research Campus-only case in Scenario A.2.e by $94,650 to $201,650 in Scenario B.2.e. The NPVs and IRRs of Scenario B.2.e are shown below in Figure 27 and Figure 28, respectively. Once again, the NPVs are stronger at higher loads, and stronger under the PV+BESS cases.

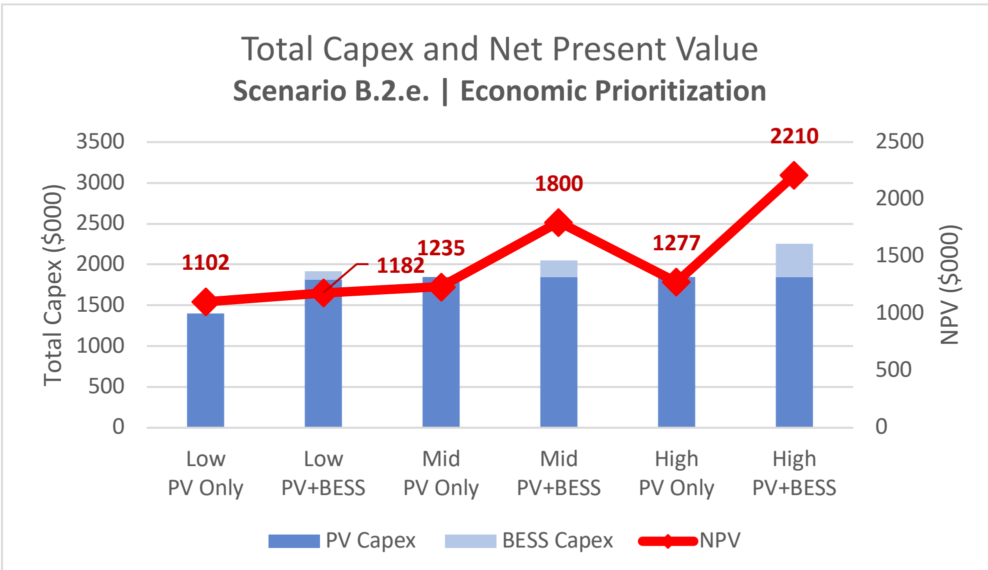

Figure 27: Scenario B.2.e Capex and NPVs

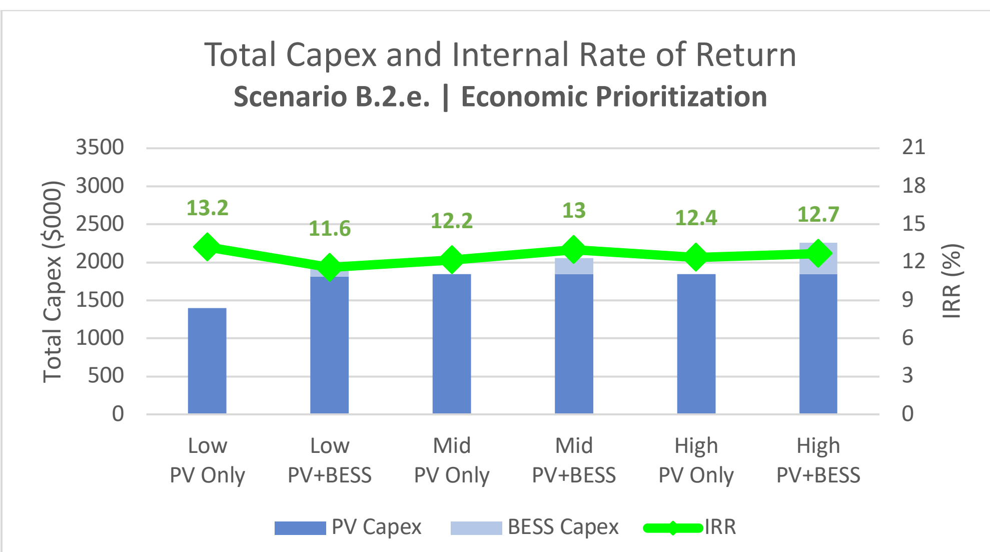

Figure 28: Scenario B.2.e Capex and IRRs

The simple and discounted payback periods of Scenario B.2.e are shown in Figure 29 below. The low-load, PV+BESS case results in the longest payback period.

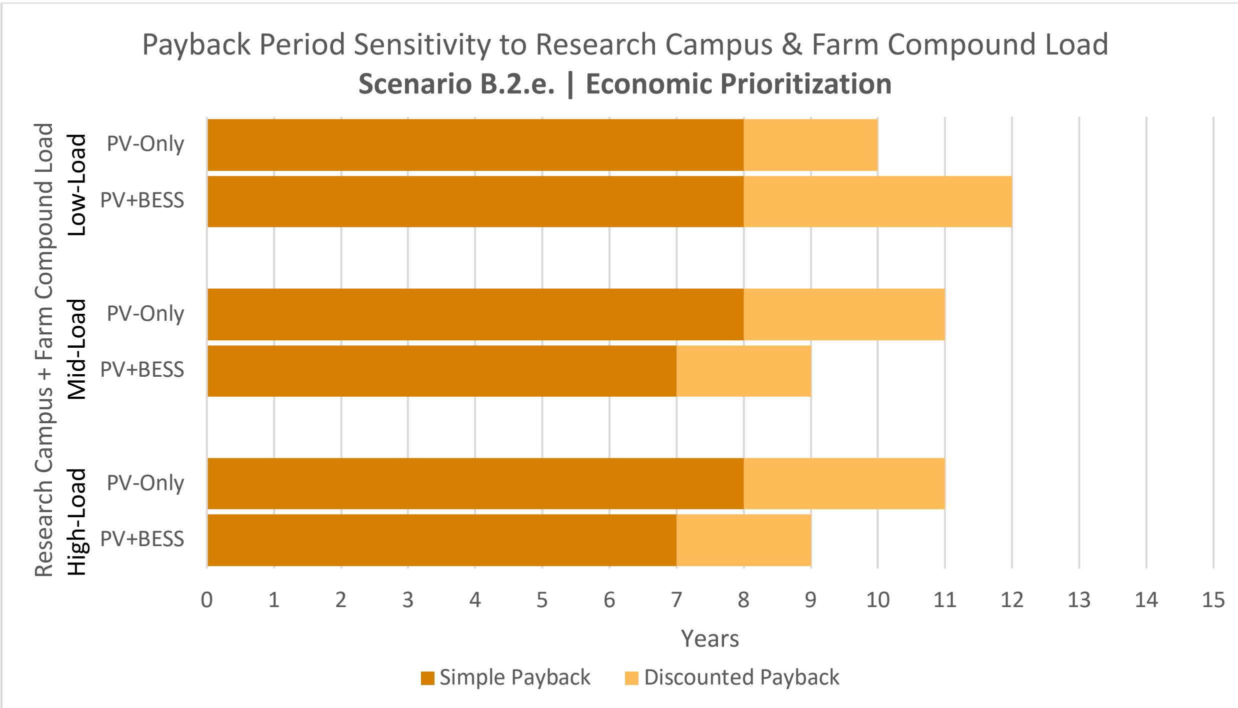

Figure 29: Scenario B.2.e Payback Periods

Whereas the Research Campus-only scenario did not result in the economically viable addition of any PV generation beyond the Pipeline Area, the combined Research Campus/Farm Compound scenario provides for the addition of relatively low-cost PV from the Power Building roof, Covered Parking Area and Ops Building roof under a number of cases. Specifically:

- Every load case in this Scenario (whether low, medium, or high) added all of the available capacity from the Power Building roof; and
- Every case in this Scenario also added all of the capacity from the Pipeline Area except for the low-load, PV-Only case, which did not add any PV generation to the Pipeline Area.

Two of the key drivers affecting the decision whether or not the Research Campus and Farm Compound loads should be combined into a single microgrid are resiliency and cost-effectiveness. From a resiliency standpoint, combining the loads will primarily benefit the Farm Compound, which will be able to take power from the Research Campus in the event of an outage. Combining the loads would also benefit the Research Campus, however, as the optimized amount of available generation and storage would be higher and more diversified under the combined scenario and the backup generator at the Research Campus could run at a higher, healthier level above the manufacturer's recommended minimum generation level.

As shown in Table 12 below, when the potential Research Campus sites are economically prioritized (i.e., in Scenarios A.2.e and B.2.e), the NPV of the combined Research Campus/Farm Compound microgrid is higher than the NPV of the Research Campus-only microgrid in all cases except for the High-Load, PV-Only case. It should be noted that if NELHA chooses to implement a PV+BESS microgrid, it would effectively rule out the potential results of the High-Load, PV-Only case below. It should also be noted that the NPVs of the merged scenarios (i.e., A.2.e and B.2.e) are higher when the PV sites are economically prioritized (versus prioritizing the Boneyard site) in every case except the Mid-Load, PV+BESS case – meaning that prioritizing PV sites by economics instead of prioritizing the Boneyard is likely a "better bet" financially.

Table 12: NPV Comparison for the
Unmerged (A) and Merged (B) Economically Prioritized Cases

Load, Technology	**NPV ($000s)**	
	Scenario A.2.e	**Scenario B.2.e**
Low, PV-Only	897	1,102
Low, PV+BESS	897	1,182
Mid, PV-Only	1,040	1,235
Mid, PV+BESS	1,291	1,800
High, PV-Only	*1,376*	1,277
High, PV+BESS	1,425	2,210

As shown in Figure 30 below, combining the Research Campus and Farm Compound loads under Schedule P also results in higher NPVs and lower total electric bills than if the loads continued to be separately metered.

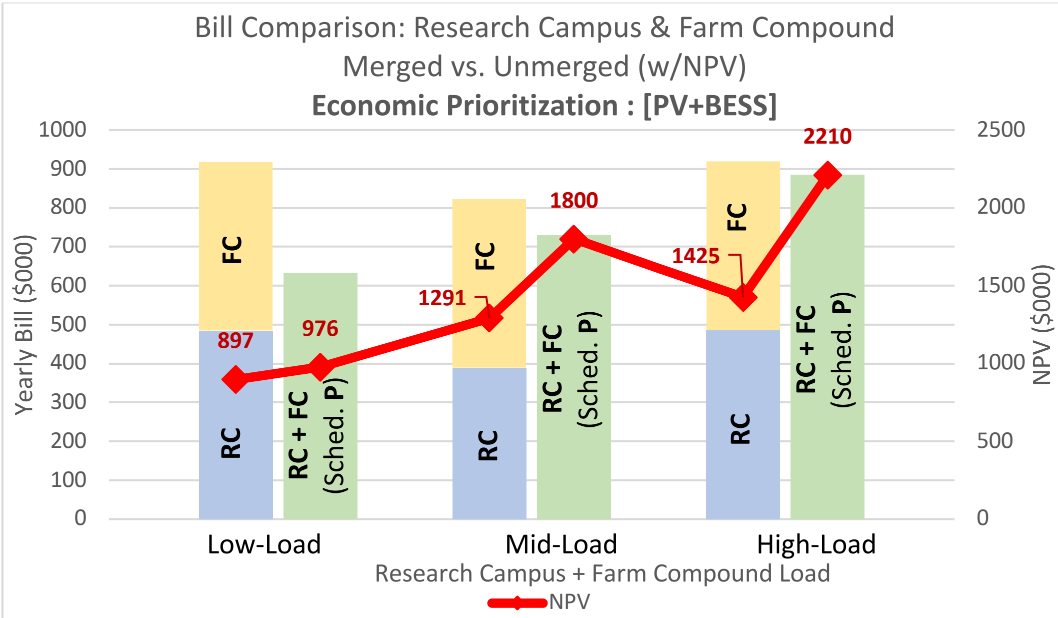

Figure 30: Scenario B.2.e Future Electric Bills Under Unmerged and Merged Cases

Of Scenarios A.1.e, A.2.e, B.1.e and B.2.e, this Scenario B.2.e is the most sensitive to deviations from the assumed loads; it has the highest upside and the lowest downside. If NELHA builds out a PV+BESS microgrid based on the low-load assumption and the actual load is at the high end of the range, the financial results significantly improve. Conversely if the microgrid is built out based on the high-load assumption and the actual load is at the low end of the range, the financial result will be negative (i.e., “out of the money” in that it will result in higher costs rather than savings) unless, for example: (1) NELHA can reduce its cost of capital to 3%; or (2) the actual load is at least in the middle of the assumed range.

3.8 Scenario B.2.n (Research Campus + Farm Compound, Economically Prioritized, New Transformer)

3.8.1 Scenario B.2.n Description

As illustrated in Figure 31 below, Scenario B.2.n represents a microgrid that merges the Research Campus and Farm Compound loads under one meter/microgrid, utilizing new PV generation from the Innovation Village and various other sites within the Research Campus, and a new HELCO step-down transformer instead of the existing transformer. Under this scenario, additional increments of PV generation are economically prioritized as follows based on their all-in average $/kW cost: (1) Innovation Village; (2) PV Test Bed; (3) Power Building roof; (4) Covered Parking Area; (5) Ops Building roof; (6) WQL roof; (7) Pipeline Area; and (8) Boneyard.

Similar to the B.1.e cases that prioritized PV generation at the Boneyard, the future energy consumption of the Research Campus and Farm Compound is a key consideration affecting the economics of the microgrid configurations and has been evaluated under three load scenarios: (1) low; (2) medium; and (3) high. HNEI's estimated cost for executing this project with 10% contingency is $564,000.[20]

The cost of adding a new HELCO transformer more than doubles the fixed cost of the microgrid design from $201,650 in Scenario B.2.e, to $564,000, thereby rendering Scenario B.2.n economically infeasible under the low- and mid-load cases. Due to these increased fixed costs, the only load scenario under which Scenario B.2.n is shown to be economically feasible in XENDEE is the high load PV+BESS case. (None of the other cases result in the addition of any new PV or storage; therefore, the results below only reflect high production under a PV+BESS case.)

[20] See Appendix H. (Fixed costs are distributed as follows: (1) Cost associated with PV installation at each location (Table 4) + (2) Fixed cost for the new HELCO transformer ($564,000) – distributed according to max kW of location.)

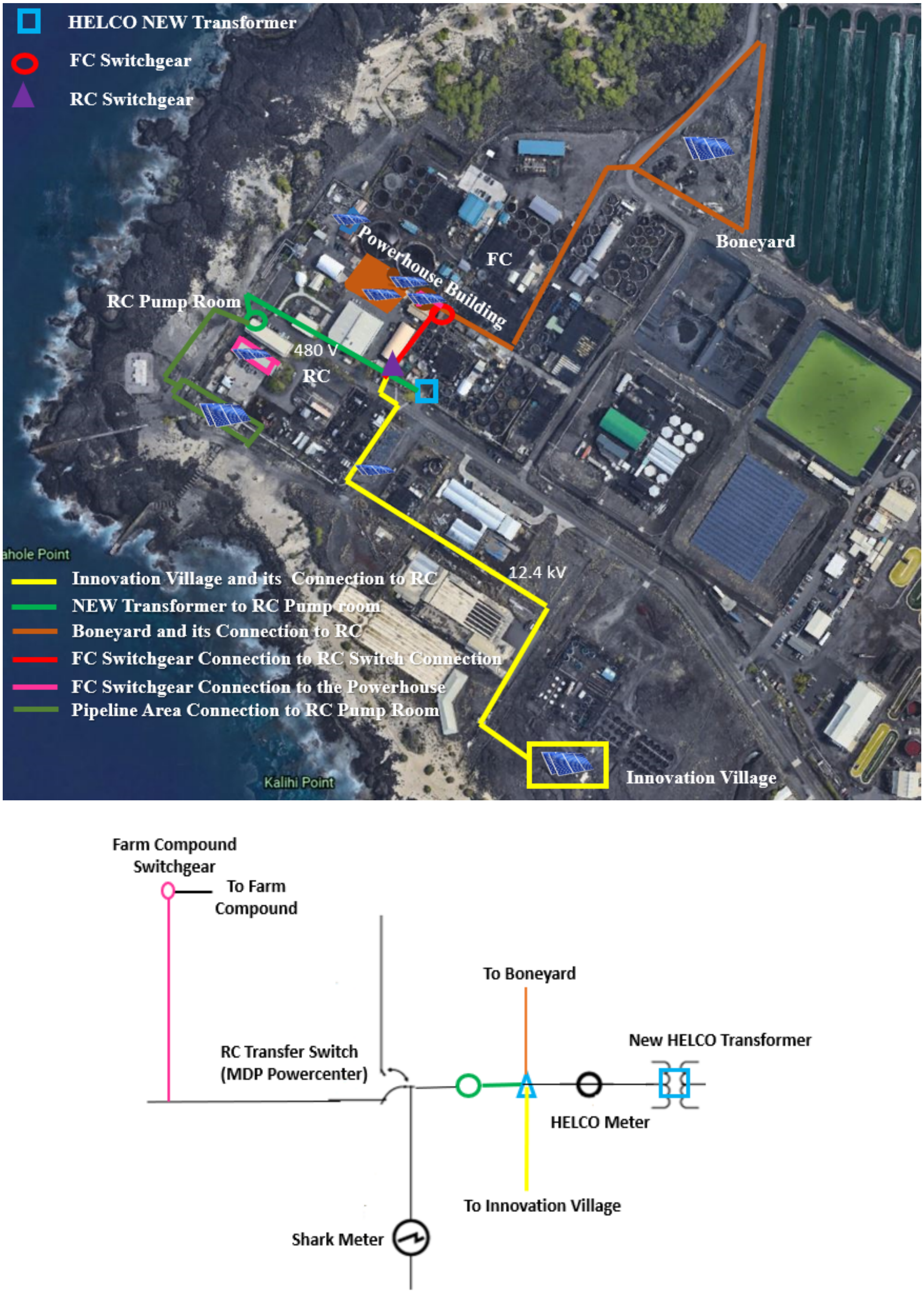

Figure 31: Scenario B.2.n, and its Schematic

3.8.2 Scenario B.2.n Results

Simulation 28:

Load	**Research Campus and Farm Compound**
PV Location Prioritization	**By Average $/kW**
Transformer	**New**
Technology	**PV + BESS**
Facilities Production	**High**
Discount Rate	**6%**

Results:

Location (max kW)		Existing (205)	Innovation Village (260)	PV Test Bed (8)	Power Bldg Roof (40)	Covered Parking (96)	Ops Bldg Roof (14)	NELHA WQL Roof (51)	Pipeline Area (123)	Cum Total Fixed Cost ($)	Cum Total Capex ($000s)	Cum Total kW	Microgrid RE%	Project Payback Period* (simple years, discounted years)
Variable ($/kW)		0	2,500	3,000	2,500	3,300	2,500	2,500	3,200					
Fixed ($)		0	0	0 + 13,00 0	28,850 + 68,000	10,000 + 163,000	12,300 + 24,000	52,000 + 87,000	55,000+ 209,000					
XENDEE Optimizations (Incremental kW, Total kWh)														
Increments	0	205, 0	---	---	---	---	---	---	---	0	0	205	8	---
	1	205, 0	**260, 571**	---	---	---	---	---	---	0	788	465	19	6, 8
	2	205, 0	260, 0	**8, 578**	---	---	---	---	---	13,000	1,005	473	19	6, 8
	3	205, 0	260, 0	8, 0	**40, 606**	---	---	---	---	109,850	1,217	513	21	8, 14
	4	205, 0	260, 0	8, 0	40, 0	**96, 705**	---	---	---	282,850	1,762	609	25	9, 17
	5	205, 0	260, 0	8, 0	40, 0	96, 0	**14, 710**	---	---	319,150	1,836	623	26	6, 7
	6	205, 0	260, 0	8, 0	40, 0	96, 0	14, 0	**51, 720**	---	458,150	2,108	674	28	8, 15
	7	205, 0	260, 0	8, 0	40, 0	96, 0	14, 0	51, 0	**123, 740**	**722,150**	**2,691**	**797**	**33**	9, 17
Cum Avg $/kW		---	2,500	2,563	2,869	3,400	3,457	3,649	4,000	Total Project Payback Period:				8, 13
Capex PV (in $000s)		---	650	37	197	490	71	267	572					
Capex BESS (in $000s)		---	138	318	333	388	391	396	407					
NPV (in $000s)		---	813	119	138	151	179	153	170	Total NPV (in $000s)				1,723
IRR (in %)		---	15.2	11.9	9.8	8.2	13	9.3	8	Total IRR (in %)				10.7
Increments		0	1	2	3	4	5	6	7					

* *Note: The Project Payback Period is for the incremental addition and is not cumulative.*

3.8.3 Scenario B.2.n Conclusion

The cost of adding a new HELCO transformer more than triples the fixed cost of this microgrid design from \$201,650 in Scenario B.2.e, to \$722,150. Including a new HELCO transformer increases the total capital expenditure by \$770,000 when compared to the mid-load PV+BESS case in Simulation 24. The renewable energy percentage decreases from 35% to 33% and the IRR decreases from 12.2% to 10.7%. However, similar to Scenarios A.1.n, A.2.n and B.1.n, the investment in a new transformer may be justified from a resiliency/business standpoint.

3.9 Scenario C (55" Pump Station)

3.9.1 Scenario C Description

As illustrated in Figure 32 below, Scenario C represents a microgrid to serve only the 55" Pump Station load utilizing new PV generation areas in close proximity to the 55" Pump Station and the existing HELCO transformer. As discussed above, the ENCORED Project at the 55" Pump Station will have a 500 kW_{DC} ground-mounted PV system, a 760 kWh/250kW battery system and an uninterrupted power supply (UPS), and is expected to be placed in service by 2022.[21] Therefore, the PV and BESS components of the ENCORED Project have been modelled in XENDEE as "existing" under this scenario, and the results of Simulation 29 below show whether and to what extent it would be economically viable to install additional PV/BESS capacity over and above that provided by the ENCORED Project.[22]

As shown in Table 5 above, the installation of additional PV at the 55" Expansion and/or OTEC sites are assumed to require a one-time incurrence of $90,000 in fixed costs for site preparation. The variable costs for the installation of PV at the 55" Expansion and OTEC sites are identical given the high-level assumptions used; therefore, although Simulation 29 below shows the 55" Expansion site as prioritized over the OTEC site, there is no economic preference for one site over the other in the model. A more detailed assessment of each site by a developer may favor one site over another.

Unlike Scenarios A and B, the load under Scenario C is assumed to remain the same as its 2019 load profile, thus negating the need for a load sensitivity analysis. Also, unlike Scenarios A and B, none of the PV+BESS cases under Scenario C resulted in the addition of any new storage; that is, the PV-Only and PV+BESS simulations for Scenario C yielded identical results. Therefore, in the interest of brevity, only the results for the PV+BESS case for Scenario C are shown below.

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[21] See NEHLA, *NELHA Announces Advanced Microgrid Project*, (Mar. 2021), available at: https://nelha.hawaii.gov/main/nelha-announces-advanced-microgrid-project/
[22] Note: This analysis does not consider battery replacement costs for the ENCORED project.

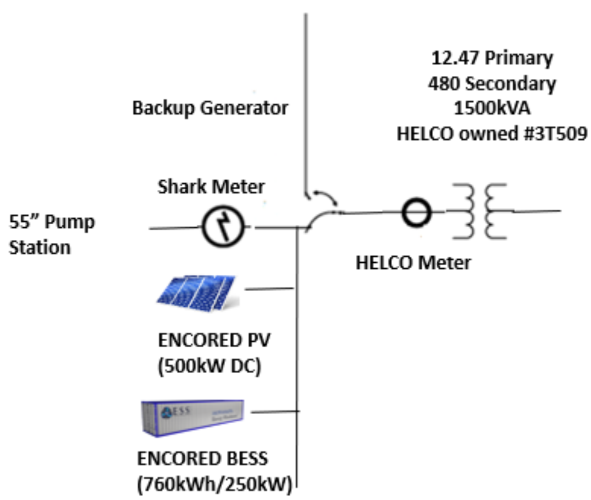

Figure 32: Scenario C (55" Pump Station Microgrid with Existing DER Systems) and its Schematic at PoC

3.9.2 Scenario C Results

Simulation 29:

Load	**55" Pump Station**
Transformer	**Existing**
Technology	**PV+BESS**
Discount Rate	**6 %**

Results:

Location (Max kW)		Existing (ENCORED)	55" Expansion (Mauka brown) (620 kW)	OTEC (Makai brown) (500 kW)	Cum Total Fixed Cost ($)	Cum Total Capex ($000s)	Cum Total kW	Microgrid RE %	Project Payback Period* (simple years, discounted years)
Variable ($/kW)		0	3,225	3,225					
Fixed ($)		0	90,000	---					
XENDEE Optimizations (Incremental kW, Total kWh)									
Increment	0	500, 760	---	---	0	0	500	35	---
	1	500, 760	**161, 0**	---	90,000	**609**	**661**	46	10, 15
					Microgrid Load Center RE%:			**43**	
Cum Avg $/kW		---	---		Total Project Payback Period:				10, 15
Capex (in $000s)		---	609						
NPV (in $000s)		---	202		Total NPV (in $000s)				202
IRR (in %)		---	9.3		Total IRR (in %)				9.3
Increment		0	1						

** Note: The Project Payback Period is for the incremental addition and is not cumulative.*

<u>Simulation 29 Key Takeaways</u>:

The optimized solution for the 55” Pump Station includes installing an additional 161 kW_{DC} of PV generation at the 55” Expansion site or OTEC site, resulting in a Microgrid RE% of 46 and Microgrid Load Center RE% of 43. The BESS provided by the ENCORED Project has adequate capacity for the optimized result; therefore, no additional storage is added.

The NPV and IRR of this Scenario are $202,000 and 9.3%, respectively, and “in the money”.

3.10 Scenario D (Booster Pump Station)

3.10.1 Scenario D Description

As shown in Figure 33, Scenario D represents a microgrid to serve the load of the Booster Pump Station, which is situated next to the 55” Pump Station. Due to its close proximity to the 55” Pump Station, the initial fixed cost for this microgrid is assumed to be *de minimus*, and thus zero.

Similar to Scenario C, the variable costs for the installation of PV at the 55” Expansion and OTEC sites under Scenario D are identical; therefore, there is no economic preference for one site over the other in the model. However, the variable costs under Scenario D ($3,000/kW) are lower than the variable costs under Scenario C ($3,250/kW). The difference assumes that the site for the relatively small PV installation for the Booster Pump Station microgrid either (1) is already prepared in spaces around the Booster Pump Station, or (2) will be prepared in the future in connection with a microgrid for the 55” Pump Station.

Also similar to Scenario C, the load under Scenario D is assumed to remain the same as 2019, and none of the PV+BESS cases under Scenario D resulted in the addition of any new storage; therefore, in the interest of brevity, only the results for the PV+BESS case for Scenario D are shown below.

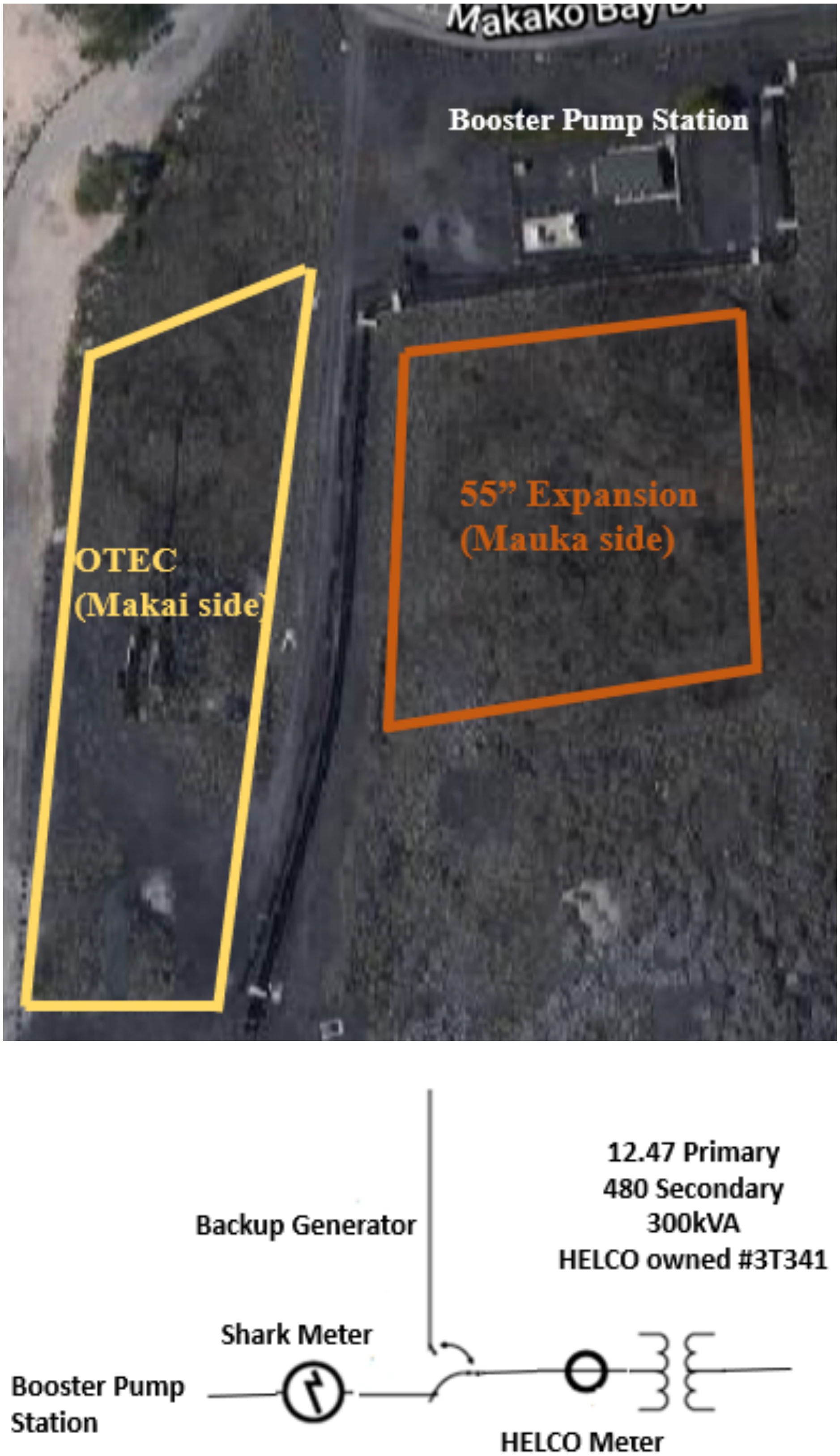

Figure 33: Scenario D (Booster Pump Station) and its Schematic at PoC

3.10.2 Scenario D Results

Simulation 30:

Load	**Booster Pump Station**
Transformer	**Existing**
Technology	**PV+BESS**
Discount Rate	**6%**

Results:

Location (Max kW)		Existing	55" Expansion (Mauka brown)	Cum Total Fixed Cost ($)	Cum Total Capex ($000s)	Cum Total kW	Microgrid RE%	Project Payback Period* (simple years, discounted years)
Variable ($/kW)		0	3,000					
Fixed ($)		0	0					
XENDEE Optimizations (Incremental kW, Total kWh)								
Increment	0	0, 0	---	0		---	---	---
Increment	1	0, 0	**18, 0**	0	**54**	**18**	19	6, 7
				Microgrid Load Center RE%:			**34**	
Cum Avg $/kW		---	---	Total Project Payback Period:				6, 7
Capex (in $000s)		---	54					
NPV (in $000s)		---	70	Total NPV (in $000s)				70
IRR (in %)		---	17.6	Total IRR (in %)				17.6
Increment		0	1					

* *Note: The Project Payback Period is for the incremental addition and is not cumulative.*

<u>Simulation 30 Key Takeaways</u>:

The optimized solution for the Booster Pump Station includes installing a modest 18 kW_{DC} of PV generation at the 55” Expansion site or OTEC site, resulting in a Microgrid RE% of 19 and Microgrid Load Center RE% of 34. No storage is added due to the small load and modest PV system addition.

The $70,000 NPV of this scenario is relatively small, but its 17.6% IRR is relatively high, due to the lack of fixed costs and lower variable costs than Scenario C.

3.11 Scenario E (55" Pump Station + Booster Pump Station)

3.11.1 Scenario E Description

As illustrated in Figure 34 below, Scenario E represents a microgrid that merges the 55" Pump Station and Booster Pump Station loads under one meter/microgrid. Similar to Scenario C, the ENCORED Project is assumed to be "existing." The $90,000 fixed cost for Scenario E is identical to the fixed cost for Scenario C, as there were no fixed costs for Scenario D. The $3,250/kW variable cost for Scenario E is assumed to be identical to the variable cost for Scenario C. It is recognized that economies of scale associated with the lower variable costs of Scenario D (18 kW @ $3,000/kW) could slightly reduce the actual variable costs that are incurred under this merged scenario; however, in the interest of conservativeness and simplicity, it is assumed that the difference is *de minimus*, and thus zero.

It is also recognized that combining the 55" Pump Station and Booster Pump Station loads requires the incurrence of some additional fixed costs. However, in discussions with NELHA it was determined that due to the proximity of the existing infrastructure at both load centers, the cost to connect the two loads would not be material and thus were not included in the financial model.

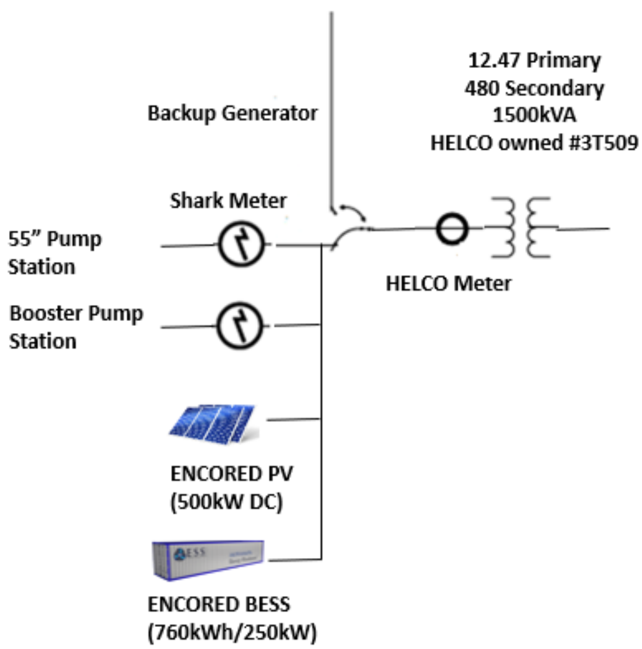

Figure 34: Scenario E (55" Pump Station plus Booster Pump Station) and its Schematic at PoC

3.11.2 Scenario E Results

Simulation 31:

Load	**Merged 55" Pump Station and Booster Pump Station**
Transformer	**Existing**
Technology	**PV+BESS**
Discount Rate	**6 %**

Results:

Location (Max kW)		Existing (ENCORED)	55" Expansion (Mauka brown) (620 kW)	OTEC (Makai brown) (500 kW)	Cum Total Fixed Cost ($)	Cum Total Capex ($000s)	Cum Total kW	Microgrid RE%	Project Payback Period* (simple years, discounted years)
Variable ($/kW)		0	3,225	3,225					
Fixed ($)		0	90,000	---					
XENDEE Optimizations (Incremental kW, Total kWh)									
Increment	0	500, 760	---	---	0		500	33	---
	1	500, 760	**211, 0**	---	90		**711**	**45**	10, 16
Cum Avg $/kW		---	---		Total Project Payback Period:				10, 16
Capex (in $000s)		---	770						
NPV (in $000s)		---	220		Total NPV (in $000s)				202
IRR (in %)		---	8.9		Total IRR (in %)				8.9
Increment		0	1						

** Note: The Project Payback Period is for the incremental addition and is not cumulative.*

Simulation 31 Key Takeaways**:**

The optimized solution for the combined 55” Pump Station and Booster Pump Station includes installing an additional 211 kW_{DC} of PV generation at the 55” Expansion site or OTEC site, resulting in a Microgrid RE% of 45. The BESS provided by the ENCORED Project has adequate capacity for the optimized result; therefore, no additional storage is added.

Migrating the Booster Pump Station load from Schedule J to Schedule P results in a larger overall PV system and lower NPV, but lower annual electric bill when compared to the sum of Scenarios C and D on an individual basis because of greater utilization of renewable energy. The 211 kW of PV added under this Scenario E is larger than the 173 kW sum of Scenarios C (161 kW) and D (18 kW); the $770,000 capex under this Scenario E is larger than the $663,000 sum of Scenarios C ($609,000) and D ($54,000); and the $220,000 NPV under this Scenario E is smaller than the $272,000 sum of Scenarios C ($202,000) and D ($70,000).

3.11.3 Scenarios C, D and E Conclusion

As shown in Figure 35 below, from a purely bill impact standpoint, NELHA would be financially better off if the 55” Pump Station and Booster Pump Station loads were merged under Schedule P (both in the 2019 *status quo* case and in a future microgrid case). Combining these loads also results in a Microgrid Load Center RE% of 45, which is higher than the unmerged percentages for the 55” Pump Station (43) and Booster Pump Station (34). As noted above, this analysis does not include any additional fixed costs to electrically connect the 55” Pump Station and Booster Pump Station loads, which would weaken the financial metrics of the merged Scenario E. However, the added resiliency that may result from combining these loads may justify the additional costs from a business standpoint, as the 8.9% IRR of Scenario E is still significantly higher than the assumed 6% Loan Interest Rate.

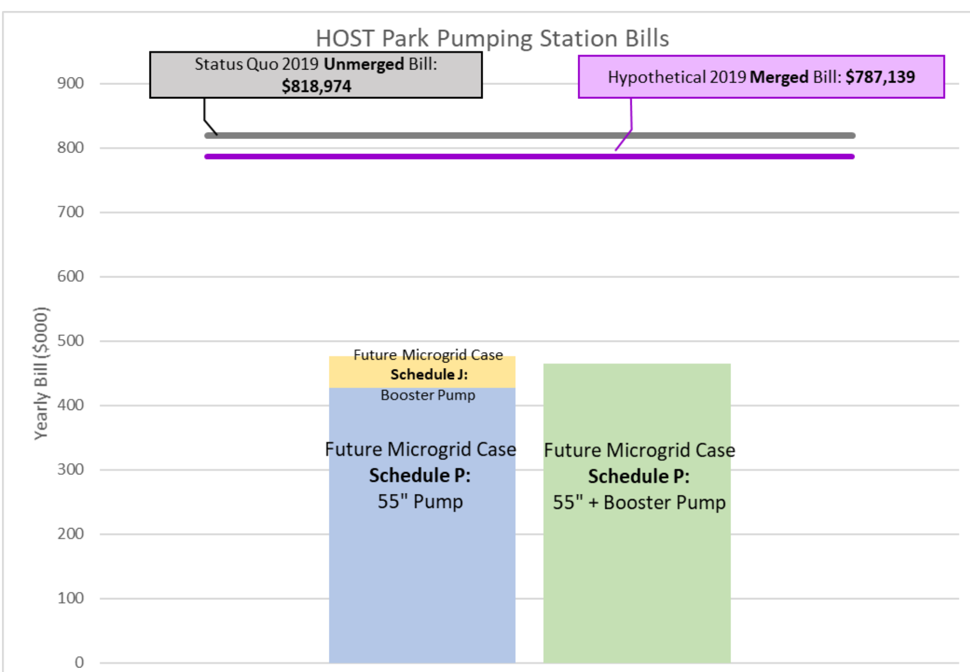

Figure 35: Existing vs. Combined 55” and Booster Pump Station Bills

4. Resiliency Scenarios

4.1 Transformer Ownership

NELHA owns the two 1,500 kVA transformers that are each currently serving the Research Campus and Farm Compound, respectively. The ownership of these transformers provides NELHA with a monthly credit to reimburse NELHA for the transformer costs (including losses at the Research Campus because the meter is located on the primary side of the transformer) that are included in HELCO's rates. In 2019, NELHA received a total of $8,182.72 in credits for the Research Campus and $2,143.99 in credits at the Farm Compound. However, if HELCO were to own the transformer at the Research Campus, NELHA would lose the primary service credit, but it would also stop paying for the losses in the transformer. Therefore, the credit for owning the transformer is closer to the credit at the Farm Compound, about $2,300. This credit is approximately 0.5% of the bill.

The downside to owning the transformer is that NELHA is responsible for the replacement of the transformer should it unexpectedly fail or reach its end of useful life. NELHA could address a potential transformer failure by: (1) buying a spare transformer in advance to replace it (these transformers cost approximately $50,000); (2) face an outage that would in all likelihood last for many months as it awaits delivery of a new transformer on order (manufacturing and delivery times to Hawaiʻi are currently about 31 weeks); (3) merge the Research Campus and Farm Compound loads behind one transformer and keep the other as a spare; or (4) have HELCO replace the existing NELHA owned transformer(s) with new HELCO owned and maintained transformer(s) (as is typically the case for utility customers). An extended outage lasting for months due to a transformer failure is the least attractive option given the dependency of many NELHA tenants on reliable supply of energy and water for their operations. Buying a spare transformer is also not ideal because of the added investment and the fact that NELHA owns only two transformers, so a spare would likely age and be placed in service very infrequently. Merging the two grids and keeping one of the existing transformers as a spare may avoid the cost of buying a new spare transformer, but has the inherent incremental risk associated with maintaining an already aged spare transformer. The safest option (yet most expensive) is to have HELCO install new transformer(s) that HELCO owns and maintains today to address the resiliency risk associated with a transformer failure and extended utility service disruption. Merging the two systems behind the existing Research Campus transformer could be a good first step to that goal.

The following sections evaluate the different microgrid scenarios and their operation in islanded mode. As noted previously, each scenario has a different microgrid footprint and a different set of loads and resources within that footprint. Scenario A includes the loads at the Research Campus, Scenario B combines the Research Campus and the Farm Compound, Scenario C includes the 55" Pump Station, Scenario D includes the Booster Pump Station, and Scenario E combines the 55" Pump Station with the Booster Pump Station.

Scenarios A and B each included two variations on the ownership of the transformer when conducting the economic analysis – one where the existing transformer is used and one where a new HELCO-owned transformer is used. The difference between those two scenarios is the added cost to install the upgrades needed to install the HELCO-owned transformer. As such, the ownership of the transformer does not affect the islanded operation discussed in Section 4.3 below.

However, the additional fixed costs associated with installing a new HELCO-owned transformer are significant and materially affect the optimized results in XENDEE. In fact, in a majority of the cases, the higher fixed costs rendered the microgrid simulations economically infeasible in XENDEE; and the few cases that were economically feasible resulted in weaker financial metrics than the cases where the existing transformer was utilized.

The cost of adding a new HELCO transformer more than doubles the fixed cost of the combined Research Campus/Farm Compound microgrid design from $201,650 in Scenario B.2.e, to $564,000, thereby rendering Scenario B.2.n economically infeasible under the low- and mid-load cases. Due to these increased fixed costs ($362,350 more), the only load scenario under which Scenario B.2.n is shown to be economically feasible in XENDEE is the high load PV+BESS case. Thus, for a combined Research Campus/Farm Compound microgrid design, from a business standpoint, the added resiliency realized by saving the existing transformer as an aged backup (and even purchasing a $50,000 new transformer as an additional backup) may be a preferred business decision relative to incurring an added $362,350 of capital investment to have HELCO purchase and install a new transformer and manage the risk of future transformer failure.

4.2 Islanded Operation – Optimized vs. Practical Operation

The backup generators at the Research Campus, 55” Pump Station and Booster Pump Station automatically take over serving the entire load at each location when there is an outage on the grid. While the Research Campus has existing PV systems within its microgrid footprint, they currently do not operate when the backup generator runs. When a power outage occurs in the Research Campus, the PV inverter’s protection scheme automatically shuts down the PV systems. The automatic transfer switch (“ATS”) then disengages the Research Campus load from the grid and connects the backup generator to the load. The backup generator starts up and the existing PV systems remain off-line. When utility grid power returns, the backup generator shuts down, the ATS transfers the load back to grid power, and the existing PV systems are restarted manually.

In general, PV inverters can run with backup generation as their synchronizing source when the microgrid load is larger than the sum of the manufacturer’s recommended minimum loading level of the backup generator and the PV capacity, and the backup generator can change its output fast enough (ramp up and down) to keep up with the fluctuations in PV power and load changes. However, the net load at the Research Campus is currently too low to run the PV system and maintain the minimum load required to run the backup generator. Even without the PV systems in operation, the load at the Research Campus is below the typical minimum load of 30% of the generator capacity.

To optimize the use of resources within a microgrid, a BESS can be used as the synchronizing source for the PV generation rather than the backup generator, if it has an inverter capable of running in "grid forming mode" when disconnected from the grid. With such a BESS, microgrids can be powered initially with the BESS to "black start" the microgrid and have the other resources such as PV and backup generation synchronize to the BESS voltage. To do this, the BESS would require an inverter large enough to power the microgrid load and a minimum level of energy maintained in the BESS at all times prior to an outage that is equal to the expected load of the microgrid for the duration of time it would take to start the backup generator to provide more energy. The backup generator and PV systems can then synchronize to the BESS as needed to provide the energy required to operate the microgrid. Unlike a generator, a BESS has no minimum load requirement and absorbs excess energy supplied by the PV systems to be used later in the day. In this configuration, the backup generator is not needed as a synchronizing source and can be turned off when energy is not required, but a synchronizing breaker is required for the generator to enable this mode of operation.

Using the BESS within a microgrid also requires more coordination and control across multiple resources than a microgrid with just one backup generator as the power source. Control algorithms, the associated monitoring and communication, and controllable resources are needed to coordinate the operation of each resource to meet the power and energy needs of the microgrid. The control system monitors the state of charge (SOC) of the BESS and optimally dispatches or curtails energy from the BESS, PV, backup generation and load throughout the day. It is HNEI's understanding that the solution provided by the ENCORED Project for the 55" Pump Station provides this type of optimization.

However, given the added costs and complexity related to optimizing microgrid operation in islanded mode and the relatively low frequency of occurrence and short duration of outages experienced at the HOST Park, it is HNEI's recommendation that a lower cost, more simplified operating scheme is better suited for the HOST Park Research Campus and Farm Compound microgrids as discussed below. As such, the resources for each microgrid scenario were optimized for normal operation using the XENDEE tool and not optimized for islanded operation. Accordingly, the added cost for larger grid-forming BESS and the control and communication systems required for the optimized islanded operation of all resources simultaneously were not included in the analysis.

4.3 Islanded Operation

4.3.1 Scenario A (A.1 and A.2)

The "A" Scenarios include the Research Campus, Innovation Village building and Hydrogen Station loads, and the existing 1,000 kW backup generator. In order to address the uncertainty of the future Hydrogen Station loads, three load cases are assessed for the Research Campus: Low, Mid, and High. The red line in Figure 36 below shows the typical minimum generation level for a 1,000 kW generator. The figure illustrates that there is more room above the minimum generation line for additional PV generation during the day than there is today without the hydrogen production, but not much, as compared to the total PV capacities shown in the embedded tables for Scenarios A.1 and A.2. With the generator running, there will be a significant amount of excess energy during the day with nowhere to shift it to throughout the day; therefore, it will need to be curtailed or turned off in islanded operation. PV generation from a large PV system site such as the Boneyard, which is only added in the high-load case in

Scenario A.1, could potentially be curtailed by a programmable logic controller ("PLC") that is able to monitor the load level of the generator. However, the benefit of even a relatively simple control system like that may not justify the cost given the infrequent and brief nature of the outages experienced at the HOST Park. It would be more complicated to control the multiple smaller PV systems chosen in the other "A" scenarios.

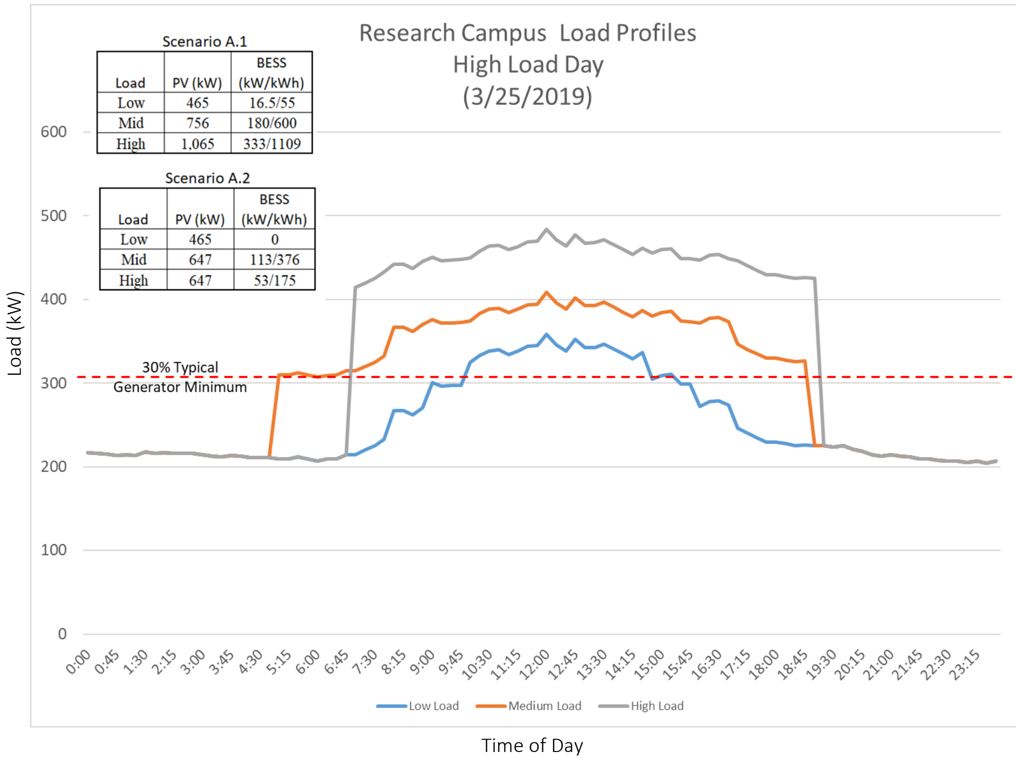

Figure 36: Scenario A Load Cases

4.3.2 Scenario B (B.1-B.2)

The "B" Scenarios have the same loads as the "A" scenarios, with the addition of the Farm Compound loads. Similar to the Research Campus-only scenario, three load cases are assumed to address the uncertainty of the future Hydrogen Station production: Low, Mid, and High. The red line in

Figure 37 again shows the typical minimum generation level for a 1,000 kW generator. With the addition of the Farm Compound load, the figure now shows that the aggregate load stays above the 300 kW minimum generator load level all day and thus provides a load better matched with the 1,000 kW generator. There will again be excess energy for all load and resource cases, but in the "B" scenarios, there is load that can be served above the 300 kW minimum generation level by the excess energy stored in a BESS outside of daylight hours. As with the "A" scenarios, PV generation from a large PV system site like the Boneyard, which is added in all of the load levels in Scenario B.1, could potentially be curtailed by a PLC that is able to monitor the load level of the generator; however, in this case the charging and discharging of the BESS would need to be brought into the dispatch mix.

Given the size of the BESS systems in the "B" scenarios, the simplest control scheme would be to set the BESS to charge during the day at modest level, enough to fill the BESS with excess PV energy throughout the day and discharge the battery at a modest level after the sun goes down, being careful to set the discharge to a level that will not drive the net load below the 300 kW generator minimum. The Boneyard PV system could then be controlled so as not to violate the generator minimum as in the "A" scenarios. Again, given the infrequent and brief nature of the outages experienced at the HOST Park, the benefit of such a system may not justify the cost, and it would be more complicated to control the multiple smaller PV systems chosen in Scenario B.2.

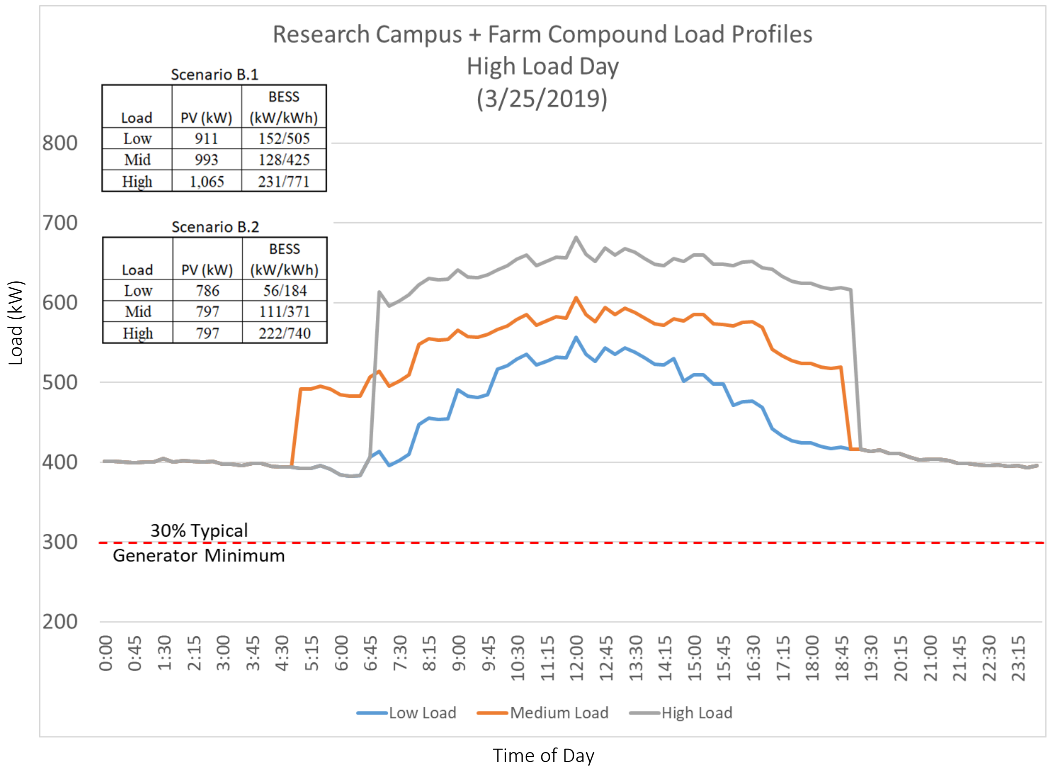

Figure 37: Scenario B Load Cases

4.3.3 Scenario C

Scenario C includes the 55" Pump Station load and its 750 kW generator. This generator's 30% minimum generation level is 225 kW, and the 55" Pump Station load ranged between 250 and 350 kW in 2019. Given these load and minimum generation levels, there is some opportunity to incorporate PV into the islanded operation of Scenario C as with the Boneyard PV system in Scenarios A and B; however, once the ENCORED Project is in service, it is HNEI's understanding that the system will optimize the use of the PV and BESS resources through the use of a grid forming BESS and a sophisticated dispatch control system. This project will provide NELHA with real-world experience with operating and maintaining such a control system and microgrid infrastructure. NELHA can then make a more informed and experience based decision if it appears worthwhile to mirror such capabilities to the Booster Pump Station and Research Campus/Farm Compound microgrids.

4.3.4 Scenario D

Scenario D includes the Booster Pump Station load and its 500 kW generator. The load at the Booster Pump Station ranged between 17 and 37 kW in 2019. Given that the typical 30% minimum generation level for the 500 kW is 150 kW, there is not enough load to run a PV system with the generator during outages.

4.3.5 Scenario E

Scenario E combines the loads and generation from Scenarios C and D. As such, the islanded operation of this scenario would be similar to Scenario C. As with Scenario C, once the ENCORED Project is up and running, the Booster Pump Station load and additional PV systems could be added and managed by the same control system. Given the proximity of the 55” Pump Station and the Booster Pump Station, combining the loads and resources of the two systems and adding them to the ENCORED Project control scheme may be a viable near term course of action.

4.4 Consolidated HOST Park Microgrid

HNEI considered the potential to create a single HOST Park microgrid that incorporated the four NELHA loads at the HOST Park. The HOST Park is currently served by a primary and an alternate HELCO feeder with switches located along the feeders and at service taps off the feeders as shown in Figure 38 below.

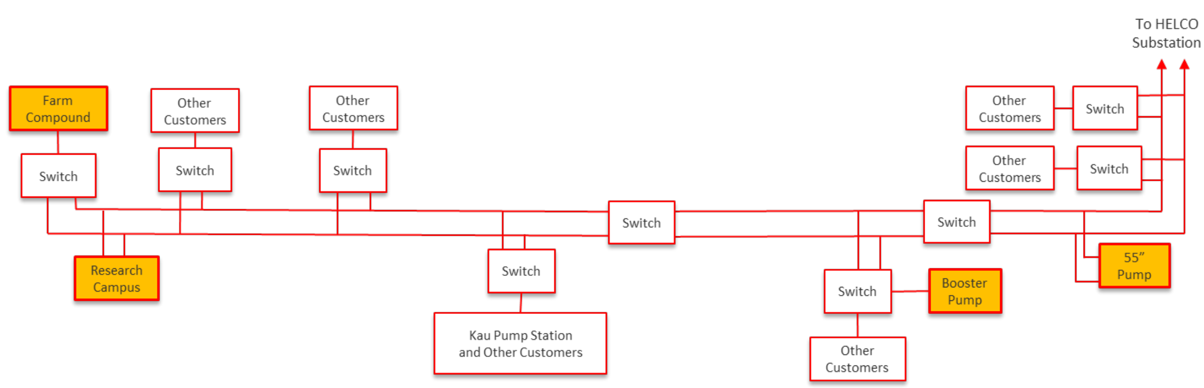

Figure 38: Existing HOST Park Primary Distribution

Given the current switch locations along the two feeders, it is possible to isolate the NELHA loads using the HELCO owned and operated switch currently between the Booster Pump Station and 55” Pump Station, if the tap to the 55” Pump Station were moved to the Booster Pump Station side of that switch as shown below in Figure 39 below. Since the cables serving the 55” Pump Station and cables going to and from the switch share a manhole near the switch, this reconfiguration could be done in that manhole relatively easily. If a grid outage is expected to have a very long duration, HELCO could dispatch its crews to open the isolation switch and the switches to other customers to create a microgrid that could be powered by the 1 MW backup generator at the Research Campus.

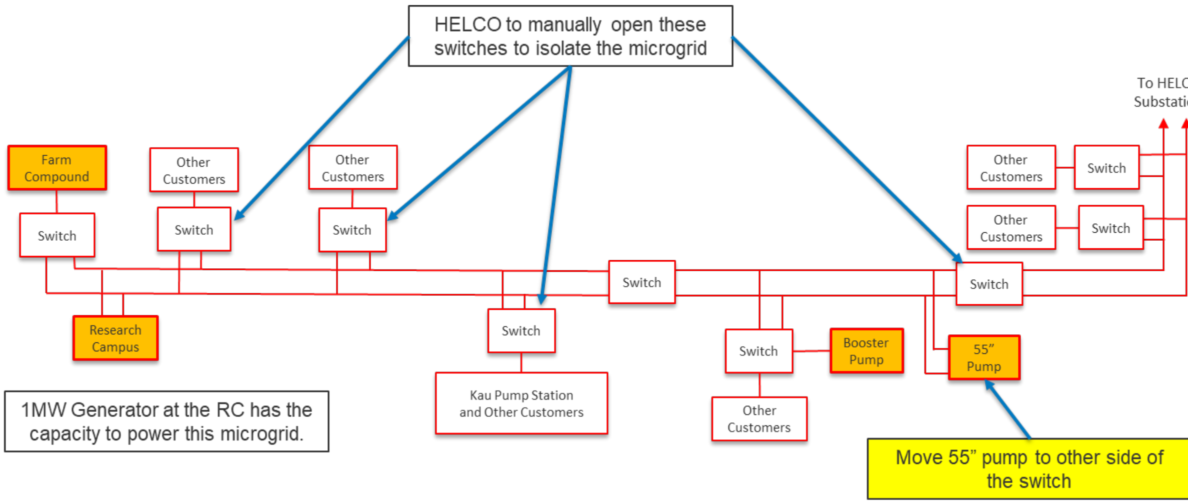

Figure 39: Single HOST Park Microgrid Configuration

While creating this configuration is technically possible, the planned ENCORED Project at the 55” Pump Station will cover the 55” Pump Station load during extended outages. If the Research Campus and Farm Compound loads are combined the only benefit of creating this new single microgrid would be to tie the Booster Pump Station to the Research Campus and Farm Compound if the Booster Pump Station load is not otherwise incorporated with the 55” Pump Station load. As such, creating two independent microgrids by combining the Research Campus with the Farm Compound and the 55” Pump Station with the Booster Pump Station would appear to be a better option at the outset, as opposed to creating a single NELHA microgrid as depicted in Figure 39. However, the single microgrid configuration can be revisited once the ENCORED Project is in operation and evaluated by NELHA, if the control system being installed by ENCORED can be extended to incorporate and control other resources at the other microgrid locations.

5. Conclusion and Next Steps

The results of the analyses above show that even without the addition of battery storage or the ability to merge the HOST Park loads, there are significant opportunities to reduce NELHA's electric bills using PV-Only solutions. However, there are even more promising and cost-effective opportunities for merged Research Campus/Farm Compound and 55" Pump Station/Booster Pump Station microgrids utilizing optimized combinations of PV generation and energy storage.

With respect to resiliency, the complexity of microgrid control systems and the resources themselves increase as the level of optimization increases. Given the relatively low frequency and short duration of the outages experienced at the HOST Park, a more simplified and lower cost operating scheme is better-suited for the HOST Park microgrids.

The ultimate microgrid design(s) for the HOST Park will be affected by numerous factors including but not limited to future load and cost assumptions; access to and cost of capital; resiliency needs; logistics; project management preferences; and regulatory considerations. HNEI looks forward to discussing the results of this report with NELHA to evaluate which solutions are best suited to meet the HOST Park's needs. In a follow-on final report, HNEI will provide a roadmap for NELHA to efficiently and effectively realize its microgrid aspirations in furtherance of the State of Hawai'i's energy mandates, policies, and goals.

Appendix A: Scenario A.1.e

Items	Unit Cost	# of Units	Total Cost	Notes
One new 12.4 kV circuit from after the RC meter to Boneyard				
Electrical conduits (ft)	$100	1,050	$105,000	$100/foot
3 × 5 handhole installation	$1,500	4	$6,000	
15kV #2 AL electrical cables ($/ft)			$12,600	1,050 * 3 cables * $4.0/foot
Electrical cable installation (manhours/span)			$2,880	1 circuit, 4 spans, 8 man-hours per span @ $90/hr prevailing wage
Cable splices ($/each)	$250	12	$3,000	4 handholes, 3 splices per handhole
Splicing (manhours/splice)			$4,104	1 circuit, 3 cables per circuit, 4 handholes, 3.8 man-hours per splice @ $90/hr prevailing wage
PV system transformer and installation cost	$30,000	1	$30,000	
Contingency 10%			$16,358	
TOTAL COST			**$179,942**	

Appendix B: Scenario A.1.n

Items[23]	Unit Cost	# of Units	Total Cost	Notes
Three new 480 circuits from the Boneyard to the RC switchgear				
Electrical conduits	$100	1,050	$105,000	$100/foot
3 × 5 handhole installation	$1,500	3	$4,500	
Electrical wire	$10	12,600	$126,000	1,050 * 12 wires * $10/foot
Electrical wire installation			$6,480	3 circuits, 4 spans, 6 man-hours per span @ $90/hr prevailing wage
Splicing			$5,040	3 circuits, 4 cables per circuit, 3 handholes, 1 man-hour per splice @ $90/hr prevailing wage + 50 per splice
New switchgear at new transformer	$100,000	1	$100,000	
Three new 480 V circuits from the new transformer to the RC Pump Room				
Electrical conduits	$100	550	$55,000	$100/foot
3 × 5 handhole installation	$1,500	3	$4,500	
Electrical wire	$10	6,600	$66,000	550 * 12 wires * $10/foot
Electrical wire installation			$6,480	3 circuits, 4 spans, 6 man-hours per span @ $90/hr prevailing wage
Splicing			$5,040	3 circuits, 4 cables per circuit, 3 handholes, 1 man-hour per splice @ $90/hr prevailing wage + 50 per splice
New panel installed at the Pump Room	$7,000	1	$7,000	
New transformer	$60,000	1	$60,000	
Contingency 10%			$55,104	
TOTAL COST			**$606,144**	

[23] The color-coding of this table corresponds with the color-coding of Figure 11.

Appendix C: Scenario A.2.e

Items	Unit Cost	# of Units	Total Cost	Notes
Circuit upgrade from Pump Room to Powerhouse (According to NELHA staff)			$100,000	
TOTAL COST			**$100,000**	

Appendix D: Scenario A.2.n

Items[24]	Unit Cost	# of Units	Total Cost	Notes
Three new 480 V circuits from the new transformer to the RC Pump Room				
Electrical conduits	$100	550	$55,000	$100/foot
3 × 5 handhole installation	$1,500	3	$4,500	
Electrical wire	$10	6,600	$66,000	550 * 12 wires * $10/foot
Electrical wire installation			$6,480	3 circuits, 4 spans, 6 man-hours per span @ $90/hr prevailing wage
Splicing			$5,040	3 circuits, 4 cables per circuit, 3 handholes, 1 man-hour per splice @ $90/hr prevailing wage + 50 per splice
New panel installed at the Pump Room	$7,000	1	$7,000	
New transformer	$60,000	1	$60,000	
New switchgear @ new transformer	$100,000	1	$100,000	
Contingency 10%			$30,402	
TOTAL COST			**$334,422**	

[24] The color-coding of this table corresponds with the color-coding of Figure 18.

Appendix E: Scenario B.1.e

Items[25]	Unit Cost	# of Units	Total Cost	Notes
One new 12.4 kV circuit from after the RC meter to Boneyard				
Electrical conduits (ft)	$100	1,050	$105,000	$100/foot
3 × 5 handhole installation	$1,500	4	$6,000	
15kV #2 AL electrical cables ($/ft)	$4	3,150	$12,600	1,050 * 3 cables * $4.0/foot
Electrical cable installation (manhours/span)			$2,880	1 circuit, 4 spans, 8 man-hours per span @ $90/hr prevailing wage
Cable splices ($/each)	$250	12	$3,000	4 handholes, 3 splices per handhole
Splicing (manhours/splice)			$4,104	1 circuit, 3 cables per circuit, 4 handholes, 3.8 man-hours per splice @ $90/hr prevailing wage
PV system transformer and installation cost	$30,000	1	$30,000	
New Farm Compound switchgear and installation labor	$100,000	1	$100,000	
Farm Compound ATS & 480V circuits from Powerhouse to FC switchgear				
Electrical conduits	$100	150	$15,000	$100/foot
3 × 5 handhole installation	$1,500	1	$1,500	
Electrical wire	$10	1,800	$18,000	150 * 12 * $10/foot
Electrical wire installation			$3,240	(3 circuits, 2 spans, 6 man-hours per span @ $90/hr prevailing Wage
Splicing			$1,680	3 circuits, 4 cables per circuit, 1 handholes, 1 man-hour per splice @ $90/hr prevailing wage + 50 per splice
New panel at Powerhouse	$10,000	1	$10,000	
Contingency 10%			$31,300	
TOTAL COST			**$344,304**	

[25] The color-coding of this table corresponds with the color-coding of Figure 19.

Appendix F: Scenario B.1.n

Items[26]	Unit Cost	# of Units	Total Cost	Notes
Three new 480 V circuits from the new RC switchgear to RC Pump Room				
Electrical conduits	$100	550	$55,000	$100/foot
3 × 5 handhole installation	$1,500	3	$4,500	
Electrical wire	$10	6,600	$66,000	550 * 12 wires * $10/foot
Electrical wire installation			$6,480	3 circuits, 4 spans, 6 man-hours per span @ $90/hr prevailing wage
Splicing			$5,040	3 circuits, 4 cables per circuit, 3 handholes, 1 man-hour per splice @ $90/hr prevailing wage + 50 per splice
New panel installed at the Pump Room	$7,000	1	$7,000	
Three new 480 V circuits from the RC switchgear to the FC switchgear				
Electrical conduits (Units: feet)	$100	300	$30,000	$100/foot
3 × 5 handhole installation	$1,500	1	$1,500	
Electrical wire	$10	3,600	$36,000	300 * 12 wires * $10/foot
Electrical wire installation			$3,240	3 circuits, 2 spans, 6 man-hours per span @ $90/hr prevailing Wage
Splicing			$1,680	3 circuits, 4 cables per circuit, 1 handhole, 1 man-hour per splice @ $90/hr prevailing wage + 50 per splice
Switchgear and installation labor			$100,000	
Three new 480 V circuits from FC switchgear to Boneyard				
Electrical conduits	$100	900	$90,000	$100/foot
3 × 5 handhole installation	$1,500	4	$6,000	
Electrical wire	$10	10,800	$108,000	900 * 12 * $10/foot
Electrical wire installation			$8,100	(3 circuits, 5 spans, 6 man-hours per span @ $90/hr prevailing Wage

[26] The color-coding of this table corresponds with the color-coding of Figure 25.

Splicing			$6,720	3 circuits, 4 cables per circuit, 4 handholes, 1 man-hour per splice @ $90/hr prevailing wage + 50 per splice
Farm Compound ATS & circuits from Powerhouse to FC switchgear				
Electrical conduits	$100	150	$15,000	$100/foot
3 × 5 handhole installation	$1,500	1	$1,500	
Electrical wire	$10	1,800	$18,000	150 * 12 * $10/foot
Electrical wire installation			$3,240	(3 circuits, 2 spans, 6 man-hours per span @ $90/hr prevailing Wage
Splicing			$1,680	3 circuits, 4 cables per circuit, 1 handholes, 1 man-hour per splice @ $90/hr prevailing wage + 50 per splice
New transformer	$60,000	1	$60,000	
New switchgear @ New transformer	$100,000	1	$100,000	
contingency 10%			$73,468	
TOTAL COST			**$808,148**	

Appendix G: Scenario B.2.e

Items[27]	Unit Cost	# of Units	Total Cost	Notes
Farm Compound ATS & circuits from Powerhouse to FC switchgear				
Electrical Conduits	$100	150	$15,000	$100/foot
3 × 5 Handhole Installation	$1,500	1	$1,500	
Electrical wire	$10	1,800	$18,000	150 * 12 * $10/foot
Electrical wire installation			$3,240	(3 circuits, 2 spans, 6 man-hours per span @ $90/hr prevailing Wage
Splicing			$1,680	3 circuits, 4 cables per circuit, 1 handholes, 1 man-hour per splice @ $90/hr prevailing wage + 50 per splice
Contingency 10%			$3,942	
TOTAL COST			**$43,362**	

[27] The color-coding of this table corresponds with the color-coding of Figure 26.

Appendix H: Scenario B.2.n

Items[28]	Unit Cost	# of Units	Total Cost	Notes
Three new 480 V circuits from the New Trans to the RC Control Room				
Electrical Conduits	$100	550	$55,000	$100/foot
3 × 5 Handhole Installation	$1,500	3	$4,500	
Electrical wire	$10	6,600	$66,000	550 * 12 wires * $10/foot
Electrical wire installation			$6,480	3 circuits, 4 spans, 6 man-hours per span @ $90/hr prevailing wage
Splicing			$5,040	3 circuits, 4 cables per circuit, 3 handholes, 1 man-hour per splice @ $90/hr prevailing wage + 50 per splice
New Panel installed at the Pump Room			$7,000	
Three new 480 V circuits from the new RC switchgear to the new FC switchgear				
Electrical Conduits (Units: feet)	$100	300	$30,000	$100/foot
3 × 5 Handhole Installation	$1,500	1	$1,500	
Electrical wire	$10	3,600	$36,000	300 * 12 wires * $10/foot
Electrical wire installation			$3,240	3 circuits, 2 spans, 6 man-hours per span @ $90/hr prevailing Wage
Splicing			$1,680	3 circuits, 4 cables per circuit, 1 handhole, 1 man-hour per splice @ $90/hr prevailing wage + 50 per splice
Switchgear and installation Labor			$100,000	
Farm Compound ATS & circuits from Powerhouse to FC switchgear				
Electrical Conduits	$100	150	$15,000	$100/foot
3 × 5 Handhole Installation	$1,500	1	$1,500	
Electrical wire	$10	1,800	$18,000	150 * 12 * $10/foot

[28] The color-coding of this table corresponds with the color-coding of Figure 31.

Electrical wire installation			$3,240	(3 circuits, 2 spans, 6 man-hours per span @ $90/hr prevailing Wage
Splicing			$1,680	3 circuits, 4 cables per circuit, 1 handholes, 1 man-hour per splice @ $90/hr prevailing wage + 50 per splice
New transformer	$60,000	1	$60,000	
New switchgear @ New transformer	$100,000	1	$100,000	
contingency 10%			$51,586	
TOTAL COST			**$567,446**	